MDU RESOURCES GROUP INC
Form 10-K
February 20, 2008

UNITED STATES SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D.C. 20549

FORM 10-K

X ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the fiscal year ended December 31, 2007

OR

TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the transition period from _____________ to ______________

Commission file number 1-3480

MDU Resources Group, Inc.
(Exact name of registrant as specified in its charter)

Delaware (State or other jurisdiction of incorporation or organization)	41-0423660 (I.R.S. Employer Identification No.)

1200 West Century Avenue
P.O. Box 5650
Bismarck, North Dakota 58506-5650
(Address of principal executive offices)
(Zip Code)

(701) 530-1000
(Registrant's telephone number, including area code)

Securities registered pursuant to Section 12(b) of the Act:

Title of each class	Name of each exchange on which registered
Common Stock, par value $1.00 and Preference Share Purchase Rights	New York Stock Exchange

Securities registered pursuant to Section 12(g) of the Act:

Preferred Stock, par value $100
(Title of Class)

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes x No o.

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Exchange Act. Yes o No x.

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes x No o.

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of the registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. x

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act (Check one):

Large accelerated filer x	Accelerated filer o
Non-accelerated filer o	Smaller Reporting Company o

(Do not check if a smaller reporting company)

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Act). Yes o No x.

State the aggregate market value of the voting common stock held by nonaffiliates of the registrant as of June 30, 2007: $5,099,834,108.

Indicate the number of shares outstanding of each of the registrant's classes of common stock, as of February 11, 2008: 182,462,076 shares.

DOCUMENTS INCORPORATED BY REFERENCE
Portions of the registrant's 2008 Proxy Statement are incorporated by reference in Part III, Items 10, 11, 12, 13 and 14 of this Report.

CONTENTS

DEFINITIONS

The following abbreviations and acronyms used in this Form 10-K are defined below:

Abbreviation or Acronym	
AFUDC	Allowance for funds used during construction
ALJ	Administrative Law Judge
Alusa	Tecnica de Engenharia Electrica - Alusa
Anadarko	Anadarko Petroleum Corporation
APB	Accounting Principles Board
APB Opinion No. 25	Accounting for Stock-Based Compensation
Army Corps	U.S. Army Corps of Engineers
Badger Hills Project	Tongue River-Badger Hills Project
Bbl	Barrel of oil or other liquid hydrocarbons
Bcf	Billion cubic feet
BER	Montana Board of Environmental Review
Big Stone Station	450-MW coal-fired electric generating facility located near Big Stone City, South Dakota (22.7 percent ownership)
Big Stone Station II	Proposed coal-fired electric generating facility located near Big Stone City, South Dakota (the Company anticipates ownership of at least 116 MW)
Bitter Creek	Bitter Creek Pipelines, LLC, an indirect wholly owned subsidiary of WBI Holdings
Black Hills Power	Black Hills Power and Light Company
BLM	Bureau of Land Management
Brascan	Brascan Brasil Ltda.
Brazilian Transmission Lines	Company's equity method investment in companies owning ECTE, ENTE and ERTE
Btu	British thermal unit
Carib Power	Carib Power Management LLC
Cascade	Cascade Natural Gas Corporation, an indirect wholly owned subsidiary of MDU Energy Capital (acquired July 2, 2007)
CBNG	Coalbed natural gas
CELESC	Centrais Elétricas de Santa Catarina S.A.
CEM	Colorado Energy Management, LLC, a former direct wholly owned subsidiary of Centennial Resources (sold in the third quarter of 2007)
CEMIG	Companhia Energética de Minas Gerais
Centennial	Centennial Energy Holdings, Inc., a direct wholly owned subsidiary of the Company
Centennial Capital	Centennial Holdings Capital LLC, a direct wholly owned subsidiary of Centennial
Centennial International	Centennial Energy Resources International, Inc., a direct wholly owned subsidiary of Centennial Resources
Centennial Power	Centennial Power, Inc., a former direct wholly owned subsidiary of Centennial Resources (sold in the third quarter of 2007)
Centennial Resources	Centennial Energy Resources LLC, a direct wholly owned subsidiary of Centennial

CERCLA	Comprehensive Environmental Response, Compensation and Liability Act
Clean Air Act	Federal Clean Air Act
Clean Water Act	Federal Clean Water Act
CMS	Cost Management Services, Inc.
Colorado Federal District Court	U.S. District Court for the District of Colorado
Company	MDU Resources Group, Inc.
D.C. Appeals Court	U.S. Court of Appeals for the District of Columbia Circuit
dk	Decatherm
DRC	Dakota Resource Council
EBSR	Elk Basin Storage Reservoir, one of Williston Basin's natural gas storage reservoirs, which is located in Montana and Wyoming
ECTE	Empresa Catarinense de Transmissão de Energia S.A.
EIS	Environmental Impact Statement
EITF	Emerging Issues Task Force
EITF No. 00-21	Revenue Arrangements with Multiple Deliverables
EITF No. 91-6	Revenue Recognition of Long-Term Power Sales Contracts
ENTE	Empresa Norte de Transmissão de Energia S.A.
EPA	U.S. Environmental Protection Agency
ERTE	Empresa Regional de Transmissão de Energia S.A.
ESA	Endangered Species Act
Exchange Act	Securities Exchange Act of 1934, as amended
FASB	Financial Accounting Standards Board
FERC	Federal Energy Regulatory Commission
Fidelity	Fidelity Exploration & Production Company, a direct wholly owned subsidiary of WBI Holdings
FIN	FASB Interpretation No.
FIN 47	Accounting for Conditional Asset Retirement Obligations - An Interpretation of FASB Statement No. 143
FIN 48	Accounting for Uncertainty in Income Taxes
Great Plains	Great Plains Natural Gas Co., a public utility division of the Company
Hartwell	Hartwell Energy Limited Partnership, a former equity method investment of the Company (sold in the third quarter of 2007)
Howell	Howell Petroleum Corporation, a wholly owned subsidiary of Anadarko
IBEW	International Brotherhood of Electrical Workers
ICWU	International Chemical Workers Union
Indenture	Indenture dated as of December 15, 2003, as supplemented, from the Company to The Bank of New York as Trustee
Innovatum	Innovatum, Inc., a former indirect wholly owned subsidiary of WBI Holdings (the stock and Innovatum's assets have been sold)
Item 8	Financial Statements and Supplementary Data
Kennecott	Kennecott Coal Sales Company
Knife River	Knife River Corporation, a direct wholly owned subsidiary of Centennial
K-Plan	Company's 401(k) Retirement Plan
kW	Kilowatts
kWh	Kilowatt-hour

LWG	Lower Willamette Group
MAPP	Mid-Continent Area Power Pool
MBbls	Thousands of barrels of oil or other liquid hydrocarbons
MBI	Morse Bros., Inc., an indirect wholly owned subsidiary of Knife River
Mcf	Thousand cubic feet
MD&A	Management's Discussion and Analysis of Financial Condition and Results of Operations
Mdk	Thousand decatherms
MDU Brasil	MDU Brasil Ltda., an indirect wholly owned subsidiary of Centennial International
MDU Construction Services	MDU Construction Services Group, Inc., a direct wholly owned subsidiary of Centennial
MDU Energy Capital	MDU Energy Capital, LLC, a direct wholly owned subsidiary of the Company
Midwest ISO	Midwest Independent Transmission System Operator, Inc.
MMBtu	Million Btu
MMcf	Million cubic feet
MMcfe	Million cubic feet equivalent
MMdk	Million decatherms
MNPUC	Minnesota Public Utilities Commission
Montana-Dakota	Montana-Dakota Utilities Co., a public utility division of the Company
Montana DEQ	Montana State Department of Environmental Quality
Montana Federal District Court	U.S. District Court for the District of Montana
Mortgage	Indenture of Mortgage dated May 1, 1939, as supplemented, amended and restated, from the Company to The Bank of New York and Douglas J. MacInnes, successor trustees
MPX	MPX Termoceara Ltda. (49 percent ownership, sold in June 2005)
MTPSC	Montana Public Service Commission
MW	Megawatt
ND Health Department	North Dakota Department of Health
NDPSC	North Dakota Public Service Commission
NEPA	National Environmental Policy Act
NHPA	National Historic Preservation Act
Ninth Circuit	U.S. Ninth Circuit Court of Appeals
NPRC	Northern Plains Resource Council
OPUC	Oregon Public Utilities Commission
Order on Rehearing	Order on Rehearing and Compliance and Remanding Certain Issues for Hearing
Oregon DEQ	Oregon State Department of Environmental Quality
PCBs	Polychlorinated biphenyls
PPA	Power purchase and sale agreement
Prairielands	Prairielands Energy Marketing, Inc., an indirect wholly owned subsidiary of WBI Holdings
Proxy Statement	Company's 2008 Proxy Statement
PSD	Prevention of Significant Deterioration
RCRA	Resource Conservation and Recovery Act
SDPUC	South Dakota Public Utilities Commission
SEC	U.S. Securities and Exchange Commission

Securities Act Industry Guide 7	Description of Property by Issuers Engaged or to be Engaged in Significant Mining Operations
SEIS	Supplemental Environmental Impact Statement
SFAS	Statement of Financial Accounting Standards
SFAS No. 71	Accounting for the Effects of Certain Types of Regulation
SFAS No. 109	Accounting for Income Taxes
SFAS No. 115	Accounting for Certain Investments in Debt and Equity Securities
SFAS No. 123	Accounting for Stock-Based Compensation
SFAS No. 123 (revised)	Share-Based Payment (revised 2004)
SFAS No. 141 (revised)	Business Combinations (revised 2007)
SFAS No. 142	Goodwill and Other Intangible Assets
SFAS No. 143	Accounting for Asset Retirement Obligations
SFAS No. 144	Accounting for the Impairment or Disposal of Long-Lived Assets
SFAS No. 148	Accounting for Stock-Based Compensation - Transition and Disclosure - an amendment of SFAS No. 123
SFAS No. 157	Fair Value Measurements
SFAS No. 158	Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans
SFAS No. 159	The Fair Value Option for Financial Assets and Financial Liabilities
SFAS No. 160	Noncontrolling Interests in Consolidated Financial Statements - an amendment of ARB No. 51 (Consolidated Financial Statements)
Sheridan System	A separate electric system owned by Montana-Dakota
SMCRA	Surface Mining Control and Reclamation Act
Stock Purchase Plan	Company's Dividend Reinvestment and Direct Stock Purchase Plan
Termoceara Generating Facility	220-MW natural gas-fired electric generating facility in the Brazilian state of Ceara, owned and operated by MPX (the Company's 49-percent ownership interest was sold in June 2005)
TRWUA	Tongue River Water Users' Association
WBI Holdings	WBI Holdings, Inc., a direct wholly owned subsidiary of Centennial
Westmoreland	Westmoreland Coal Company
Williston Basin	Williston Basin Interstate Pipeline Company, an indirect wholly owned subsidiary of WBI Holdings
WUTC	Washington Utilities and Transportation Commission
Wyoming DEQ	Wyoming State Department of Environmental Quality
Wyoming Federal District Court	U.S. District Court for the District of Wyoming
WYPSC	Wyoming Public Service Commission

PART I

FORWARD-LOOKING STATEMENTS

This Form 10-K contains forward-looking statements within the meaning of Section 21E of the Exchange Act. Forward-looking statements are all statements other than statements of historical fact, including without limitation those statements that are identified by the words "anticipates," "estimates," "expects," "intends," "plans," "predicts" and similar expressions, and include statements concerning plans, objectives, goals, strategies, future events or performance, and underlying assumptions (many of which are based, in turn, upon further assumptions) and other statements that are other than statements of historical facts. From time to time, the Company may publish or otherwise make available forward-looking statements of this nature, including statements contained within Item 7 – MD&A – Prospective Information.

Forward-looking statements involve risks and uncertainties, which could cause actual results or outcomes to differ materially from those expressed. The Company's expectations, beliefs and projections are expressed in good faith and are believed by the Company to have a reasonable basis, including without limitation, management's examination of historical operating trends, data contained in the Company's records and other data available from third parties. Nonetheless, the Company's expectations, beliefs or projections may not be achieved or accomplished.

Any forward-looking statement contained in this document speaks only as of the date on which the statement is made, and the Company undertakes no obligation to update any forward-looking statement or statements to reflect events or circumstances that occur after the date on which the statement is made or to reflect the occurrence of unanticipated events. New factors emerge from time to time, and it is not possible for management to predict all of the factors, nor can it assess the effect of each factor on the Company's business or the extent to which any factor, or combination of factors, may cause actual results to differ materially from those contained in any forward-looking statement. All forward-looking statements, whether written or oral and whether made by or on behalf of the Company, are expressly qualified by the risk factors and cautionary statements in this Form 10-K, including statements contained within Item 1A – Risk Factors.

ITEMS 1 AND 2. BUSINESS AND PROPERTIES

GENERAL

The Company is a diversified natural resource company, which was incorporated under the laws of the state of Delaware in 1924. Its principal executive offices are at 1200 West Century Avenue, P.O. Box 5650, Bismarck, North Dakota 58506-5650, telephone (701) 530-1000.

Montana-Dakota, through the electric and natural gas distribution segments, generates, transmits and distributes electricity and distributes natural gas in Montana, North Dakota, South Dakota and Wyoming. Great Plains distributes natural gas in western Minnesota and southeastern North Dakota. Cascade distributes natural gas in Washington and Oregon. These operations also supply related value-added products and services.

The Company, through its wholly owned subsidiary, Centennial, owns WBI Holdings (comprised of the pipeline and energy services and the natural gas and oil production segments), Knife River (construction materials and contracting segment – formerly construction materials and mining), MDU Construction Services (construction services segment), Centennial Resources and Centennial Capital (both reflected in the Other category).

The Company's equity method investment in the Brazilian Transmission Lines, as discussed in Item 8 – Note ––4, is reflected in the Other category.

As discussed in Item 8 – Note 3, the Company sold its domestic independent power production assets in the third quarter of 2007.

As of December 31, 2007, the Company had 12,293 employees with 161 employed at MDU Resources Group, Inc., 900 at Montana-Dakota, 35 at Great Plains, 376 at Cascade, 570 at WBI Holdings, 4,905 at Knife River, 5,343 at MDU Construction Services and three at Centennial Resources. The number of employees at certain Company operations fluctuates during the year depending upon the number and size of construction projects. The Company considers its relations with employees to be satisfactory.

At Montana-Dakota and Williston Basin, 437 and 79 employees, respectively, are represented by the IBEW. Labor contracts with such employees are in effect through May 30, 2011, and March 31, 2008, for Montana-Dakota and Williston Basin, respectively. Williston Basin is in negotiations on its labor contract.

At Cascade, 210 employees are represented by the ICWU. Labor contracts with such employees extend to April 1, 2009, and remain in force thereafter from year to year unless terminated by either party.

Knife River has 43 labor contracts that represent approximately 900 of its construction materials employees. Knife River is in negotiations on six of its labor contracts.

MDU Construction Services has 81 labor contracts representing the majority of its employees. The majority of the labor contracts contain provisions that prohibit work stoppages or strikes and provide for binding arbitration dispute resolution in the event of an extended disagreement.

The Company's principal properties, which are of varying ages and are of different construction types, are generally in good condition, are well maintained and are generally suitable and adequate for the purposes for which they are used.

The financial results and data applicable to each of the Company's business segments, as well as their financing requirements, are set forth in Item 7 – MD&A and Item 8 – Note 16 and Supplementary Financial Information.

The operations of the Company and certain of its subsidiaries are subject to federal, state and local laws and regulations providing for air, water and solid waste pollution control; state facility-siting regulations; zoning and planning regulations of certain state and local authorities; federal health and safety regulations and state hazard communication standards. The Company believes that it is in substantial compliance with these regulations, except as to what may be ultimately determined with regard to items discussed in Environmental matters in Item 8 – Note 20. There are no pending CERCLA actions for any of the Company's properties, other than the Portland, Oregon, Harbor Superfund Site.

Governmental regulations establishing environmental protection standards are continuously evolving and, therefore, the character, scope, cost and availability of the measures that will permit compliance with these laws or regulations cannot be accurately predicted. Disclosure regarding specific environmental matters applicable to each of the Company's businesses is set forth under each business description below.

This annual report on Form 10-K, the Company's quarterly reports on Form 10-Q, the Company's current reports on Form 8-K and any amendments to those reports filed or furnished pursuant to Section 13(a) or 15(d) of the Exchange Act are available free of charge through the Company's Web site as soon as reasonably practicable after the Company has electronically filed such reports with, or furnished such reports to, the SEC. The Company's Web site address is www.mdu.com. The information available on the Company's Web site is not part of this annual report on Form 10-K.

ELECTRIC
General Montana-Dakota provides electric service at retail, serving over 120,000 residential, commercial, industrial and municipal customers located in 177 communities and adjacent rural areas as of December 31, 2007. The principal properties owned by Montana-Dakota for use in its electric operations include interests in eight electric generating facilities, as further described under System Supply, System Demand and Competition, and approximately 3,000 and

4,500 miles of transmission and distribution lines, respectively. Montana-Dakota has obtained and holds, or is in the process of renewing, valid and existing franchises authorizing it to conduct its electric operations in all of the municipalities it serves where such franchises are required. Montana-Dakota intends to protect its service area and seek renewal of all expiring franchises. As of December 31, 2007, Montana-Dakota's net electric plant investment approximated $390 million.

Substantially all of Montana-Dakota's electric properties are subject to the lien of the Mortgage and to the junior lien of the Indenture.

The percentage of Montana-Dakota's 2007 retail electric utility operating revenues by jurisdiction is as follows: North Dakota – 62 percent; Montana – 21 percent; South Dakota – 7 percent; and Wyoming – 10 percent. Retail electric rates, service, accounting and certain security issuances are subject to regulation by the NDPSC, MTPSC, SDPUC and WYPSC. The interstate transmission and wholesale electric power operations of Montana-Dakota also are subject to regulation by the FERC under provisions of the Federal Power Act, as are interconnections with other utilities and power generators, the issuance of securities, accounting and other matters. Montana-Dakota participates in the Midwest ISO wholesale energy market.

The Midwest ISO is a regional transmission organization responsible for operational control of the transmission systems of its members. The Midwest ISO provides security center operations, tariff administration and operates a day-ahead and real-time energy market. As a member of Midwest ISO, Montana-Dakota's generation is sold into the Midwest ISO energy market and its energy needs are purchased from that market.

System Supply, System Demand and Competition Through an interconnected electric system, Montana-Dakota serves markets in portions of western North Dakota, including Bismarck, Dickinson and Williston; eastern Montana, including Glendive and Miles City; and northern South Dakota, including Mobridge. The interconnected system consists of eight electric generating facilities, which have an aggregate nameplate rating attributable to Montana-Dakota's interest of 455,555 kW and a total summer net capability of 483,360 kW. Montana-Dakota's four principal generating stations are steam-turbine generating units using coal for fuel. The nameplate rating for Montana-Dakota's ownership interest in these four stations (including interests in the Big Stone Station and the Coyote Station, aggregating 22.7 percent and 25.0 percent, respectively) is 327,758 kW. During 2007, Montana-Dakota began construction on 19,500 kW of wind-powered electric generation near Baker, Montana. Approximately 1,500 kW of this project came online in December 2007, and the remainder came online in early 2008, and is reflected in the following table. Three combustion turbine peaking stations and the wind-powered electric generating facility supply the balance of Montana-Dakota's interconnected system electric generating capability.

In September 2005, Montana-Dakota entered into a contract for seasonal capacity from a neighboring utility, starting at 85 MW in 2007, increasing to 105 MW in 2011, with an option for capacity in 2012. In April 2007, Montana-Dakota entered into an additional contract for seasonal capacity of 10 MW in May through October of each year continuing through 2010. Energy also will be purchased as needed from the Midwest ISO market. In 2007, Montana-Dakota purchased approximately 13 percent of its kWh needs for its interconnected system through the Midwest ISO market.

The following table sets forth details applicable to the Company's electric generating stations:

Generating Station	Type	Nameplate Rating (kW)	Summer Capability (kW)	2007 Net Generation (kWh in thousands)
North Dakota:				
Coyote*	Steam	103,647	106,750	750,670

Heskett	Steam	86,000	103,260	618,431
Williston	Combustion Turbine	7,800	9,600	(5)**
South Dakota:				
Big Stone*	Steam	94,111	105,950	554,967
Montana:				
Lewis & Clark	Steam	44,000	52,300	314,672
Glendive	Combustion Turbine	77,347	78,900	12,477
Miles City	Combustion Turbine	23,150	22,300	2,623
Diamond Willow	Wind	19,500	4,300***	16
		455,555	483,360	2,253,851

* Reflects Montana-Dakota's ownership interest.

** Station use, to meet MAPP's accreditation requirements, exceeded generation.

***Pending accreditation.

Virtually all of the current fuel requirements of the Coyote, Heskett and Lewis & Clark stations are met with coal supplied by subsidiaries of Westmoreland. Contracts with Westmoreland for the Coyote, Heskett and Lewis & Clark stations expire in May 2016, April 2011 and December 2012, respectively. The Coyote coal supply agreement provides for the purchase of coal necessary to supply the coal requirements of the Coyote Station or 30,000 tons per week, whichever may be the greater quantity at contracted pricing. The maximum quantity of coal during the term of the agreement, and any extension, is 75 million tons. The Heskett and Lewis & Clark coal supply agreements provide for the purchase of coal necessary to supply the coal requirements of these stations at contracted pricing. Montana-Dakota estimates the Heskett and Lewis & Clark coal requirement to be in the range of 500,000 to 600,000 tons, and 250,000 to 350,000 tons per contract year, respectively.

A coal supply agreement, entered into in August 2007 with Kennecott, meets the majority of the Big Stone Station’s fuel requirements for the years 2008 to 2010 at contracted pricing. The Kennecott agreement provides for the purchase of 2.1 million, 1.8 million and 1.0 million tons of coal in 2008, 2009 and 2010, respectively.

During the years ended December 31, 2005, through December 31, 2007, the average cost of coal purchased, including freight at Montana-Dakota's electric generating stations (including the Big Stone and Coyote stations) was as follows:

Years Ended December 31,		2007		2006		2005
Average cost of coal per MMBtu	$	1.29	$	1.26	$	1.14
Average cost of coal per ton	$	18.71	$	18.48	$	17.01

The maximum electric peak demand experienced to date attributable to sales to retail customers on the interconnected system was 525,643 kW in July 2007. Montana-Dakota's latest forecast for its interconnected system indicates that its annual peak will continue to occur during the summer and the peak demand growth rate through 2013 will approximate less than 1 percent annually.

Montana-Dakota expects that it has adequate capacity available through existing baseload generating stations, wind-powered generation, turbine peaking stations and firm contracts to meet the peak demand requirements of its customers through 2012. Future capacity that is needed to replace contracts and meet system growth requirements is expected to be met by constructing new generation resources or acquiring additional capacity through power contracts. For additional information regarding potential power generation projects, see Item 7 – MD&A – Prospective Information – Electric.

Montana-Dakota has major interconnections with its neighboring utilities and considers these interconnections adequate for coordinated planning, emergency assistance, exchange of capacity and energy and power supply reliability.

Through the Sheridan System, Montana-Dakota serves Sheridan, Wyoming, and neighboring communities. The maximum peak demand experienced to date and attributable to Montana-Dakota sales to retail customers on that system was approximately 60,600 kW and occurred in July 2007.

In December 2004, Montana-Dakota entered into a power supply contract with Black Hills Power to purchase up to 74,000 kW of capacity annually during the period from January 1, 2007, to December 31, 2016. This contract also provides an option for Montana-Dakota to purchase 25 MW of an existing or future baseload coal-fired electric generating facility from Black Hills Power to serve the Sheridan load.

Montana-Dakota is subject to competition in varying degrees, in certain areas, from rural electric cooperatives, on-site generators, co-generators and municipally owned systems. In addition, competition in varying degrees exists between electricity and alternative forms of energy such as natural gas.

Regulatory Matters and Revenues Subject to Refund Fuel adjustment clauses contained in North Dakota and South Dakota jurisdictional electric rate schedules allow Montana-Dakota to reflect monthly increases or decreases in fuel and purchased power costs (excluding demand charges). In North Dakota, the Company is deferring electric fuel and purchased power costs (excluding demand charges) that are greater or less than amounts presently being recovered through its existing rate schedules. In Wyoming, an annual Electric Power Supply Cost Adjustment mechanism allows Montana-Dakota to reflect increases or decreases in fuel and purchased power costs (including demand charges) related to power supply and Montana-Dakota is deferring costs that are greater or less than amounts presently being recovered through its existing rate schedules. Such orders generally provide that these amounts are recoverable or refundable through rate adjustments within a period ranging from 14 to 25 months from the time such costs are paid. In Montana, such cost changes are includable in general rate filings. For additional information, see Item 8 – Note 19.

In July 2007, Montana-Dakota filed an electric rate case with the MTPSC. For additional information, see Item 8 – Note 19.

In November 2006, Montana-Dakota filed an application with the NDPSC requesting an advance determination of prudence of Montana-Dakota's ownership interest in Big Stone Station II. For additional information, see Item 8 – Note 19.

Environmental Matters Montana-Dakota's electric operations are subject to federal, state and local laws and regulations providing for air, water and solid waste pollution control; state facility-siting regulations; zoning and planning regulations of certain state and local authorities; federal health and safety regulations; and state hazard communication standards. Montana-Dakota believes it is in substantial compliance with these regulations.

Montana-Dakota's electric generating facilities have Title V Operating Permits, under the Clean Air Act, issued by the states in which it operates. Each of these permits has a five-year life. Near the expiration of these permits, renewal applications are submitted. Permits continue in force beyond the expiration date, provided the application for renewal is submitted by the required date, usually six months prior to expiration. Renewal is pending for the Big Stone Station Title V Operating Permit which expired in 2002. An application for renewal will be submitted for the Coyote Station Title V Operating Permit that expires in September 2008. State water discharge permits issued under the requirements of the Clean Water Act are maintained for power production facilities on the Yellowstone and Missouri rivers. These permits also have five-year lives. Montana-Dakota renews these permits as necessary prior to expiration. Other permits held by these facilities may include an initial siting permit, which is typically a one-time, preconstruction permit issued by the state; state permits to dispose of combustion by-products; state authorizations to withdraw water for operations; and Army Corps permits to construct water intake structures. Montana-Dakota's Army Corps permits grant one-time permission to construct and do not require renewal. Other permit terms vary and the permits are renewed as necessary.

Montana-Dakota's electric operations are conditionally exempt small-quantity hazardous waste generators and subject only to minimum regulation under the RCRA. Montana-Dakota routinely handles PCBs from its electric operations in accordance with federal requirements. PCB storage areas are registered with the EPA as required.

In November 2006, the Sierra Club sent a notice of intent to file a citizen suit in federal court under the Clean Air Act to the co-owners, including Montana-Dakota, of the Big Stone Station. For more information regarding this notice, see Item 8 – Note 20.

Montana-Dakota incurred $7.8 million of environmental expenditures in 2007. Expenditures are estimated to be $29.1 million, $19.5 million and $6.3 million in 2008, 2009 and 2010, respectively, to maintain environmental compliance as new emission controls are required. Projects will include sulfur-dioxide and mercury control equipment installation at electric generating facilities. For matters involving Montana-Dakota and the ND Health Department, see Item 8 – Note 20.

NATURAL GAS DISTRIBUTION

General The Company's natural gas distribution operations consist of Montana-Dakota, Great Plains and Cascade. Montana-Dakota sells natural gas at retail, serving over 234,000 residential, commercial and industrial customers in 145 communities and adjacent rural areas as of December 31, 2007, and provides natural gas transportation services to certain customers on its system. Great Plains sells natural gas at retail, serving over 22,000 residential, commercial and industrial customers in 19 communities and adjacent rural areas as of December 31, 2007, and provides natural gas transportation services to certain customers on its system. Cascade sells natural gas at retail, serving over 250,000 residential, commercial and industrial customers in 98 communities and adjacent rural areas as of December 31, 2007, and provides natural gas transportation services to certain customers on its system. These services for the three public utility operations are provided through distribution systems aggregating approximately 11,400 miles. The natural gas distribution operations have obtained and hold, or are in the process of renewing, valid and existing franchises authorizing them to conduct their natural gas operations in all of the municipalities they serve where such franchises are required. These operations intend to protect their service areas and seek renewal of all expiring franchises. As of December 31, 2007, Montana-Dakota's, Great Plains' and Cascade's net natural gas distribution plant investment approximated $527.5 million.

Substantially all of Montana-Dakota's natural gas distribution properties are subject to the lien of the Mortgage and to the junior lien of the Indenture.

The percentage of the natural gas distribution operations' 2007 natural gas utility operating sales revenues by jurisdiction is as follows: North Dakota – 23 percent; Minnesota – 8 percent; Montana – 15 percent; Oregon – 10 percent; South Dakota – 12 percent; Washington – 29 percent and Wyoming – 3 percent. The above percentages reflect operating sales revenues of Cascade since the date of acquisition. The natural gas distribution operations are subject to regulation by the NDPSC, MNPUC, MTPSC, OPUC, SDPUC, WUTC and WYPSC regarding retail rates, service, accounting and certain security issuances.

System Supply, System Demand and Competition The natural gas distribution operations serve retail natural gas markets, consisting principally of residential and firm commercial space and water heating users, in portions of North Dakota, including Bismarck, Dickinson, Wahpeton, Williston, Minot and Jamestown; western Minnesota, including Fergus Falls, Marshall and Crookston; eastern Montana, including Billings, Glendive and Miles City; central and eastern Oregon, including Bend and Pendleton; western and north-central South Dakota, including Rapid City, Pierre and Mobridge; western and south-central Washington, including Bellingham, Bremerton, Longview, Moses Lake, Mount Vernon, Tri-Cities, Walla Walla and Yakima; and northern Wyoming, including Sheridan. These markets are highly seasonal and sales volumes depend largely on the weather, the effects of which are mitigated in certain jurisdictions by a weather normalization mechanism discussed in Regulatory Matters.

Competition in varying degrees exists between natural gas and other fuels and forms of energy. The natural gas distribution operations have established various natural gas transportation service rates for their distribution businesses to retain interruptible commercial and industrial loads. Certain of these services include transportation under flexible rate schedules whereby interruptible customers can avail themselves of the advantages of open access transportation on regional transmission pipelines, including the system of Williston Basin, Northern Natural Gas Company, Viking Gas Transmission Company and Northwest Pipeline GP. These services have enhanced Montana-Dakota's, Great Plains' and Cascade's competitive posture with alternative fuels, although certain of Montana-Dakota's and Cascade's customers have bypassed the respective distribution systems by directly accessing transmission pipelines located within close proximity. These bypasses did not have a material effect on results of operations.

The natural gas distribution operations obtain their system requirements directly from producers, processors and marketers. Such natural gas is supplied by a portfolio of contracts specifying market-based pricing and is transported under transportation agreements by Williston Basin, South Dakota Intrastate Pipeline Company, Northern Border Pipeline Company, Viking Gas Transmission Company, Northern Natural Gas Company, Source Gas, TransCanada Alberta System, TransCanada Foothills System, Northwestern Energy, Northwest Pipeline GP, Gas Transmission Northwest Corporation and Spectra Energy Gas Transmission to provide firm service to their customers. Montana-Dakota also has contracted with Williston Basin, Great Plains with Northern Natural Gas Company, and Cascade with Northwest Pipeline GP, to provide firm storage services that enable all three operations to meet winter peak requirements as well as allow them to better manage their natural gas costs by purchasing natural gas at more uniform daily volumes throughout the year. Demand for natural gas, which is a widely traded commodity, has historically been sensitive to seasonal heating and industrial load requirements as well as changes in market price. Montana-Dakota, Great Plains and Cascade believe that, based on regional supplies of natural gas and the pipeline transmission network currently available through their suppliers and pipeline service providers, supplies are adequate to meet their system natural gas requirements for the next five years.

Regulatory Matters Montana-Dakota's, Great Plains' and Cascade's retail natural gas rate schedules contain clauses permitting adjustments in rates based upon changes in natural gas commodity, transportation and storage costs. Current tariffs allow for recovery or refunds of under or over recovered gas costs within a period ranging from 14 to 28 months.

Montana-Dakota's North Dakota, South Dakota-Black Hills and South Dakota-East River area natural gas tariffs contain a weather normalization mechanism applicable to firm customers that adjusts the distribution delivery charge revenues to reflect weather fluctuations during the billing period from November 1 through May 1.

Cascade has received approval for decoupling its margins from weather and conservation in Oregon, and has also received approval of a decoupling mechanism in Washington which allows it to recover margin differences resulting from customer conservation. Cascade also has an earnings sharing mechanism with respect to its Oregon jurisdictional operations as required by the OPUC.

Environmental Matters The natural gas distribution operations are subject to federal, state and local environmental, facility-siting, zoning and planning laws and regulations. Montana-Dakota, Great Plains and Cascade believe they are in substantial compliance with those regulations.

Natural gas distribution operations are conditionally exempt small-quantity hazardous waste generators and subject only to minimum regulation under the RCRA. Montana-Dakota, Great Plains and Cascade routinely handle PCBs from their natural gas operations in accordance with federal requirements. PCB storage areas are registered with the EPA as required.

Montana-Dakota, Great Plains, and Cascade did not incur any material environmental expenditures in 2007 and, except as to what may be ultimately determined with regard to the issues described below, do not expect to incur any material capital expenditures related to environmental compliance with current laws and regulations in relation to the natural gas distribution operations through 2010.

Montana-Dakota completed remediation of a manufactured gas plant located in Bismarck, North Dakota, in 2007. Expenses related to this work were approximately $1.0 million and are expected to be recovered in rates through the regulatory process. In addition, Montana-Dakota has had an economic interest in five other historic manufactured gas plants within its service territory, none of which are currently being actively investigated, and for which any remediation expenses are not expected to be material. Cascade has had an economic interest in nine former manufactured gas plants within its service territory. Cascade has been involved with other potentially responsible parties in the investigation of a manufactured gas plant site in Oregon, with remediation of this site pending additional investigation. See Item 8 – Note 20 for a further discussion of this site and an additional site for which Cascade has received claim notice. Cascade believes the cost of claims for investigation and remediation of contamination at these sites is covered by insurance. To the extent not covered by insurance, Cascade will seek recovery of costs through its rates.

CONSTRUCTION SERVICES
General MDU Construction Services consists of diversified infrastructure construction companies specializing in the construction and maintenance of electric and natural gas distribution and transmission lines, and communication lines as well as inside electrical wiring, cabling and mechanical work, fire protection, utility excavation and the manufacture and distribution of specialty equipment. These services are provided to utilities and large manufacturing, commercial, industrial, institutional and government customers.

In 2007, the Company acquired a construction service business in Nevada. This acquisition was not material to the Company.

Construction and maintenance crews are active year round. However, activity in certain locations may be seasonal in nature due to the effects of weather.

MDU Construction Services operates a fleet of owned and leased trucks and trailers, support vehicles and specialty construction equipment, such as backhoes, excavators, trenchers, generators, boring machines and cranes. In addition, as of December 31, 2007, MDU Construction Services owned or leased facilities in 16 states. This space is used for offices, equipment yards, warehousing, storage and vehicle shops. At December 31, 2007, MDU Construction Services' net plant investment was approximately $48.2 million.

MDU Construction Services' backlog is comprised of the uncompleted portion of services to be performed under job-specific contracts. The backlog at December 31, 2007, was approximately $827 million compared to $527 million at December 31, 2006. MDU Construction Services expects to complete a significant amount of this backlog during the year ending December 31, 2008. Due to the nature of its contractual arrangements, in many instances MDU Construction Services' customers are not committed to the specific volumes of services to be purchased under a contract, but rather MDU Construction Services is committed to perform these services if and to the extent requested by the customer. Therefore, there can be no assurance as to the customer's requirements during a particular period or that such estimates at any point in time are predictive of future revenues.

This industry is experiencing a shortage of skilled laborers in certain areas. MDU Construction Services works with the National Electrical Contractors Association, the IBEW and other trade associations on hiring and recruiting a qualified workforce.

Competition MDU Construction Services operates in a highly competitive business environment. Most of MDU Construction Services' work is obtained on the basis of competitive bids or by negotiation of either cost-plus or fixed-price contracts. The workforce and equipment are highly mobile, providing greater flexibility in the size and location of MDU Construction Services' market area. Competition is based primarily on price and reputation for quality, safety and reliability. The size and location of the services provided, as well as the state of the economy, will be factors in the number of competitors that MDU Construction Services will encounter on any particular project. MDU Construction Services believes that the diversification of the services it provides, the markets it serves throughout the United States and the management of its workforce will enable it to effectively operate in this competitive environment.

Utilities and independent contractors represent the largest customer base for this segment. Accordingly, utility and subcontract work accounts for a significant portion of the work performed by MDU Construction Services and the amount of construction contracts is dependent to a certain extent on the level and timing of maintenance and construction programs undertaken by customers. MDU Construction Services relies on repeat customers and strives to maintain successful long-term relationships with these customers.

Environmental Matters MDU Construction Services' operations are subject to regulation customary for the industry, including federal, state and local environmental compliance. MDU Construction Services believes it is in substantial compliance with these regulations.

The nature of MDU Construction Services' operations is such that few, if any, environmental permits are required. Operational convenience supports the use of petroleum storage tanks in several locations, which are permitted under state programs authorized by the EPA. MDU Construction Services has no ongoing remediation related to releases from petroleum storage tanks. MDU Construction Services' operations are conditionally exempt small-quantity waste generators, subject to minimal regulation under the RCRA. Federal permits for specific construction and maintenance jobs that may require these permits are typically obtained by the hiring entity, and not by MDU Construction Services.

MDU Construction Services did not incur any material environmental expenditures in 2007 and does not expect to incur any material capital expenditures related to environmental compliance with current laws and regulations through 2010.

PIPELINE AND ENERGY SERVICES

General Williston Basin, the regulated business of WBI Holdings, owns and operates over 3,700 miles of transmission, gathering and storage lines and owns or leases and operates 30 compressor stations in the states of Montana, North Dakota, South Dakota and Wyoming. Three underground storage fields in Montana and Wyoming provide storage services to local distribution companies, producers, natural gas marketers and others, and serve to enhance system deliverability. Williston Basin's system is strategically located near five natural gas producing basins, making natural gas supplies available to Williston Basin's transportation and storage customers. The system has 11 interconnecting points with other pipeline facilities allowing for the receipt and/or delivery of natural gas to and from other regions of the country and from Canada. At December 31, 2007, Williston Basin's net plant investment was approximately $245.6 million. Under the Natural Gas Act, as amended, Williston Basin is subject to the jurisdiction of the FERC regarding certificate, rate, service and accounting matters.

Bitter Creek, the nonregulated pipeline business, owns and operates gathering facilities in Colorado, Kansas, Montana and Wyoming. Bitter Creek also owns a one-sixth interest in the assets of various offshore gathering pipelines, an associated onshore pipeline and related processing facilities. In total, these facilities include over 1,900 miles of field gathering lines and 85 owned or leased compression facilities, some of which interconnect with Williston Basin's system. In addition, Bitter Creek provides installation sales and/or leasing of alternate energy delivery systems, primarily propane air facilities, energy efficiency product sales and installation services to large end users.

WBI Holdings, through its energy services business, provides natural gas purchase and sales services to local distribution companies, producers, other marketers and a limited number of large end users, primarily using natural gas produced by the Company's natural gas and oil production segment. Certain of the services are provided based on contracts that call for a determinable quantity of natural gas. WBI Holdings currently estimates that it can adequately meet the requirements of these contracts. WBI Holdings transacts a substantial majority of its pipeline and energy services business in the northern Great Plains and Rocky Mountain regions of the United States.

System Demand and Competition Williston Basin competes with several pipelines for its customers' transportation, storage and gathering business and at times may discount rates in an effort to retain market share. However, the strategic location of Williston Basin's system near five natural gas producing basins and the availability of underground storage and gathering services provided by Williston Basin and affiliates along with interconnections with other pipelines serve to enhance Williston Basin's competitive position.

Although certain of Williston Basin's firm customers, including its largest firm customer Montana-Dakota, serve relatively secure residential and commercial end users, they generally all have some price-sensitive end users that could switch to alternate fuels.

Williston Basin transports substantially all of Montana-Dakota's natural gas, primarily utilizing firm transportation agreements, which for the year ended December 31, 2007, represented 57 percent of Williston Basin's currently subscribed firm transportation contract demand. Montana-Dakota has a firm transportation agreement with Williston Basin for a term of five years expiring in June 2012. In addition, Montana-Dakota has a contract with Williston Basin to provide firm storage services to facilitate meeting Montana-Dakota's winter peak requirements for a term of 20 years expiring in July 2015.

Bitter Creek competes with several pipelines for existing customers and the expansion of its systems to gather natural gas in new areas. Bitter Creek's strong position in the fields in which it operates, its focus on customer service and the variety of services it offers, along with its interconnection with various other pipelines, serve to enhance its competitive position.

System Supply Williston Basin's underground natural gas storage facilities have a certificated storage capacity of approximately 353 Bcf, including 193 Bcf of working gas capacity, 85 Bcf of cushion gas and 75 Bcf of native gas. The native gas includes an estimated 29 Bcf of recoverable gas. Williston Basin's storage facilities enable its customers to purchase natural gas at more uniform daily volumes throughout the year and, thus, facilitate meeting winter peak requirements. For information regarding natural gas storage legal proceedings, see Item 1A – Risk Factors – Other Risks and Item 8 – Note 20.

Natural gas supplies emanate from traditional and nontraditional natural gas production activities in the region and from off-system supply sources. While certain traditional regional supply sources are in various stages of decline, incremental supply from nontraditional sources have been developed which have helped support Williston Basin's supply needs. This includes new natural gas supply associated with the continued development of the Bakken play in Montana and North Dakota. The Powder River Basin, including the Company's CBNG assets, also provides a nontraditional natural gas supply to the Williston Basin system. For additional information regarding CBNG legal proceedings, see Item 1A – Risk Factors – Environmental and Regulatory Risks and Item 8 – Note 20. In addition, off-system supply sources are available through the Company's interconnections with other pipeline systems. Williston Basin expects to facilitate the movement of these supplies by making available its transportation and storage services. Williston Basin will continue to look for opportunities to increase transportation, gathering and storage services through system expansion and/or other pipeline interconnections or enhancements that could provide substantial future benefits.

Regulatory Matters and Revenues Subject to Refund In December 1999, Williston Basin filed a general natural gas rate change application with the FERC. For additional information, see Item 8 – Note 19.

Environmental Matters WBI Holdings' pipeline and energy services operations are generally subject to federal, state and local environmental, facility-siting, zoning and planning laws and regulations. WBI Holdings believes it is in substantial compliance with those regulations.

Ongoing operations are subject to the Clean Air Act and the Clean Water Act. Administration of many provisions of these laws has been delegated to the states where Williston Basin and Bitter Creek operate, and permit terms vary. Some permits require annual renewal, some have terms ranging from one to five years and others have no expiration date. Permits are renewed as necessary.

Detailed environmental assessments are included in the FERC's permitting processes for both the construction and abandonment of Williston Basin's natural gas transmission pipelines and storage facilities.

WBI Holdings' pipeline and energy services operations did not incur any material environmental expenditures in 2007 and do not expect to incur any material capital expenditures related to environmental compliance with current laws and regulations through 2010.

NATURAL GAS AND OIL PRODUCTION

General Fidelity is involved in the acquisition, exploration, development and production of natural gas and oil resources. Fidelity's activities include the acquisition of producing properties and leaseholds with potential development opportunities, exploratory drilling and the operation and development of natural gas and oil production properties. Fidelity continues to seek additional reserve and production growth opportunities through these activities. Future growth is dependent upon its success in these endeavors. Fidelity shares revenues and expenses from the development of specified properties in proportion to its ownership interests.

Fidelity's business is focused primarily in three core regions: Rocky Mountain, Mid-Continent/Gulf States and Offshore Gulf of Mexico.

Rocky Mountain

Fidelity's properties in this region are primarily located in the states of Colorado, Montana, North Dakota, Utah and Wyoming. Fidelity owns in fee or holds natural gas and oil leases for the properties it operates that are in the Bonny Field located in eastern Colorado, the Baker Field in southeastern Montana and southwestern North Dakota, the Bowdoin area located in north-central Montana, the Powder River Basin of Montana and Wyoming, the Bakken formation in North Dakota, the Paradox Basin of Utah, and the Big Horn Basin of Wyoming. Fidelity also owns nonoperated natural gas and oil interests and undeveloped acreage positions in this region.

Mid-Continent/Gulf States

This region includes properties in Alabama, Louisiana, New Mexico, Oklahoma and Texas. Fidelity owns in fee or holds natural gas and oil leases for the properties it operates that are in the Tabasco and Texan Gardens fields of Texas. In addition, Fidelity owns several nonoperated interests and undeveloped acreage positions in this region. On January 31, 2008, Fidelity completed the acquisition of natural gas properties located in Rusk County in eastern Texas. For additional information, see Item 8 – Note 21.

Offshore Gulf of Mexico

Fidelity has nonoperated interests throughout the Offshore Gulf of Mexico. These interests are primarily located in the shallow waters off the coasts of Texas and Louisiana.

Operating Information Annual net production by region for 2007 was as follows:

Region	Natural Gas (MMcf)	Oil (MBbls)	Total (MMcfe)	Percent of Total
Rocky Mountain	48,832	1,287	56,553	74%
Mid-Continent/Gulf States	9,602	727	13,962	18
Offshore Gulf of Mexico	4,364	351	6,473	8
Total	62,798	2,365	76,988	100%

Well and Acreage Information Gross and net productive well counts and gross and net developed and undeveloped acreage related to Fidelity's interests at December 31, 2007, were as follows:

	Gross*	Net**
Productive wells:		
Natural gas	3,978	3,180
Oil	3,797	233
Total	7,775	3,413
Developed acreage (000's)	751	379
Undeveloped acreage (000's)	1,039	481

* Reflects well or acreage in which an interest is owned.
** Reflects Fidelity's percentage of ownership.

Exploratory and Development Wells The following table reflects activities relating to Fidelity's natural gas and oil wells drilled and/or tested during 2007, 2006 and 2005:

	Net Exploratory			Net Development			
	Productive	Dry Holes	Total	Productive	Dry Holes	Total	Total
2007	4	5	9	317	16	333	342
2006	4	1	5	331	1	332	337
2005	2	3	5	312	25	337	342

At December 31, 2007, there were 170 gross (139 net) wells in the process of drilling or under evaluation, 160 of which were development wells and 10 of which were exploratory wells. These wells are not included in the previous table. Fidelity expects to complete the drilling and testing of the majority of these wells within the next 12 months.

The information in the table above should not be considered indicative of future performance nor should it be assumed that there is necessarily any correlation between the number of productive wells drilled and quantities of reserves found or economic value. Productive wells are those that produce commercial quantities of hydrocarbons whether or not they produce a reasonable rate of return.

Competition The natural gas and oil industry is highly competitive. Fidelity competes with a substantial number of major and independent natural gas and oil companies in acquiring producing properties and new leases for future exploration and development, and in securing the equipment, services and expertise necessary to explore, develop and operate its properties.

Environmental Matters Fidelity's natural gas and oil production operations are generally subject to federal, state and local environmental, facility-siting, zoning and planning laws and regulations. Fidelity believes it is in substantial compliance with these regulations.

The ongoing operations of Fidelity are subject to the Clean Water Act, the Clean Air Act, and other federal and state environmental regulations. Administration of many provisions of the federal laws has been delegated to the states where Fidelity operates, and permit terms vary. Some permits have terms ranging from one to five years and others have no expiration date.

Detailed environmental assessments and/or environmental impact statements under federal and state laws are required as part of the permitting process incidental to the commencement of drilling and production operations as well as in the closure, abandonment and reclamation of facilities.

In connection with production operations, Fidelity has incurred certain capital expenditures related to water handling. For 2007, capital expenditures for water handling in compliance with current laws and regulations were approximately $4.7 million and are estimated to be approximately $3.7 million, $5.7 million and $4.5 million in 2008, 2009 and 2010, respectively. These water handling costs are primarily related to the CBNG properties. For more information regarding CBNG legal proceedings, see Item 1A – Risk Factors and Item 8 – Note 20.

Reserve Information Estimates of reserves are arrived at using actual historical wellhead production trends and/or standard reservoir engineering methods utilizing available geological, geophysical, engineering and economic data. Other factors used in the reserve estimates are current natural gas and oil prices, current estimates of well operating and future development costs, taxes, timing of operations, and the interest owned by the Company in the well. The reserve estimates are prepared by internal engineers and are reviewed by management. These estimates are refined as new information becomes available.

Fidelity's recoverable proved reserves by region at December 31, 2007, are as follows:

Region	Natural Gas (MMcf)	Oil (MBbls)	Total (MMcfe)	Percent of Total	PV-10 Value * (in millions)
Rocky Mountain	392,174	22,118	524,883	74%	$ 1,398.4
Mid-Continent/Gulf States	119,500	7,616	165,197	23	527.0
Offshore Gulf of Mexico	12,063	878	17,329	3	82.1
Total reserves	523,737	30,612	707,409	100%	$ 2,007.5

* PV-10 value represents the discounted future net cash flows attributable to proved reserves before income taxes, discounted at 10 percent. The standardized measure of discounted future net cash flows in Item 8 – Supplementary Financial Information represents the present value of future cash flows attributable to proved reserves after income taxes, discounted at 10 percent.

For additional information related to natural gas and oil interests, see Item 8 – Note 1 and Supplementary Financial Information.

CONSTRUCTION MATERIALS AND CONTRACTING

General Knife River operates construction materials and contracting businesses headquartered in Alaska, California, Hawaii, Idaho, Iowa, Minnesota, Montana, North Dakota, Oregon, Texas, Washington and Wyoming. These operations mine, process and sell construction aggregates (crushed stone, sand and gravel); produce and sell asphalt mix and supply liquid asphalt for various commercial and roadway applications; and supply ready-mixed concrete for use in most types of construction, including roads, freeways and bridges, as well as homes, schools, shopping centers, office buildings and industrial parks. Although not common to all locations, other products include the sale of cement, various finished concrete products and other building materials and related construction services.

During 2007, the Company acquired construction materials and contracting businesses with operations in North Dakota, Texas and Wyoming. None of these acquisitions was material to the Company.

Knife River continues to investigate the acquisition of other construction materials properties, particularly those relating to construction aggregates and related products such as ready-mixed concrete, asphalt and related construction services.

The construction materials business had approximately $462 million in backlog at December 31, 2007, compared to $483 million at December 31, 2006. The Company anticipates that a significant amount of the current backlog will be completed during the year ending December 31, 2008.

Competition Knife River's construction materials products are marketed under highly competitive conditions. Price is the principal competitive force to which these products are subject, with service, quality, delivery time and proximity to the customer also being significant factors. The number and size of competitors varies in each of Knife River's principal market areas and product lines.

The demand for construction materials products is significantly influenced by the cyclical nature of the construction industry in general. In addition, construction materials activity in certain locations may be seasonal in nature due to the effects of weather. The key economic factors affecting product demand are changes in the level of local, state and federal governmental spending, general economic conditions within the market area that influence both the commercial and private sectors, and prevailing interest rates.

Knife River is not dependent on any single customer or group of customers for sales of its products and services, the loss of which would have a materially adverse effect on its construction materials businesses.

Reserve Information Reserve estimates are calculated based on the best available data. These data are collected from drill holes and other subsurface investigations, as well as investigations of surface features such as mine highwalls and other exposures of the aggregate reserves. Mine plans, production history and geologic data also are utilized to estimate reserve quantities. Most acquisitions are made of mature businesses with established reserves, as distinguished from exploratory-type properties.

Estimates are based on analyses of the data described above by experienced internal mining engineers, operating personnel and geologists. Property setbacks and other regulatory restrictions and limitations are identified to determine the total area available for mining. Data described above are used to calculate the thickness of aggregate materials to be recovered. Topography associated with alluvial sand and gravel deposits is typically flat and volumes of these materials are calculated by simply applying the thickness of the resource over the areas available for mining. Volumes are then converted to tons by using an appropriate conversion factor. Typically, 1.5 tons per cubic yard in the ground is used for sand and gravel deposits.

Topography associated with the hard rock reserves is typically much more diverse. Therefore, using available data, a final topography map is created and computer software is utilized to compute the volumes between the existing and final topographies. Volumes are then converted to tons by using an appropriate conversion factor. Typically, 2 tons per cubic yard in the ground is used for hard rock quarries.

Estimated reserves are probable reserves as defined in Securities Act Industry Guide 7. Remaining reserves are based on estimates of volumes that can be economically extracted and sold to meet current market and product applications. The reserve estimates include only salable tonnage and thus exclude waste materials that are generated in the crushing and processing phases of the operation. Approximately 1.1 billion tons of the 1.2 billion tons of aggregate reserves are permitted reserves. The remaining reserves are on properties that are expected to be permitted for mining under current regulatory requirements. The data used to calculate the remaining reserves may require revisions in the future to account for changes in customer requirements and unknown geological occurrences. The years remaining were calculated by dividing remaining reserves by current-year sales. Actual useful lives of these reserves will be subject to, among other things, fluctuations in customer demand, customer specifications, geological conditions and changes in mining plans.

The following table sets forth details applicable to the Company's aggregate reserves under ownership or lease as of December 31, 2007, and sales for the years ended December 31, 2007, 2006 and 2005:

Number of Sites (Crushed Stone)	Number of Sites (Sand & Gravel)	Tons Sold (000's)	Estimated Reserves	Lease	Reserve Life

Production Area	owned	leased	owned	leased	2007	2006	2005	(000's tons)	Expiration	(years)
Central MN	---	1	49	52	2,639	4,834	4,608	90,833	2008-2028	34
Portland, OR	1	4	5	3	5,372	5,862	5,559	255,034	2008-2055	47
Northern CA	1	---	7	2	2,534	3,031	4,180	53,106	2046	21
Southwest OR	4	7	12	5	3,686	4,425	3,892	110,332	2008-2031	30
Eugene, OR	3	3	4	2	2,007	3,026	2,009	174,989	2008-2046	87
Hawaii	---	6	---	---	3,081	3,167	2,891	68,031	2011-2037	22
Central MT	---	---	5	1	2,424	2,619	2,408	40,068	2023	17
Anchorage, AK	---	---	1	---	1,118	1,142	1,307	19,712	N/A	18
Northwest MT	---	---	8	5	1,318	1,434	1,679	24,161	2008-2020	18
Southern CA	---	2	---	---	69	244	166	95,330	2035	Over 100
Bend, OR/WA/ Boise, ID	2	2	5	3	2,652	1,788	1,731	103,354	2010-2012	39
Northern MN	2	---	19	17	753	520	968	30,802	2008-2016	41
Northern IA/ Southern MN	18	10	8	27	1,592	2,024	2,063	65,423	2008-2017	41
ND/SD	---	---	2	35	943	1,157	1,205	43,247	2008-2031	46
Eastern TX	1	2	1	4	1,290	917	1,255	26,969	2008-2012	21
Casper, WY	---	---	---	2	116	5	2	13,862	2008	Over 100
Sales from other sources					5,318	9,405	11,281	---		
					36,912	45,600	47,204	1,215,253		

The 1.2 billion tons of estimated aggregate reserves at December 31, 2007, is comprised of 509 million tons that are owned and 706 million tons that are leased. Approximately 49 percent of the tons under lease have lease expiration dates of 20 years or more. The weighted average years remaining on all leases containing estimated probable aggregate reserves is approximately 19 years, including options for renewal that are at Knife River's discretion. Based on 2007 sales from leased reserves, the average time necessary to produce remaining aggregate reserves from such leases is approximately 47 years. Some sites have leases that expire prior to the exhaustion of the estimated reserves. The estimated reserve life assumes, based on Knife River's experience, that leases will be renewed to allow sufficient time to fully recover these reserves.

The following table summarizes Knife River's aggregate reserves at December 31, 2007, 2006 and 2005, and reconciles the changes between these dates:

	2007	2006	2005
		(000's of tons)	
Aggregate reserves:			
Beginning of year	1,248,099	1,273,696	1,257,498
Acquisitions	29,740	7,300	53,495
Sales volumes*	(31,594)	(36,195)	(35,923)
Other**	(30,992)	3,298	(1,374)
End of year	1,215,253	1,248,099	1,273,696

* Excludes sales from other sources.
**Includes revisions of previous estimates.

Lignite Deposits The Company has lignite deposits and leases at its former Gascoyne Mine site in North Dakota. These lignite deposits are currently not being mined and are not associated with an operating mine. The lignite deposits are of a high moisture content and it is not economical to mine and ship the lignite to other distant markets. However, should a power plant be constructed near the area, the Company may have the opportunity to participate in supplying lignite to fuel a plant. As of December 31, 2007, Knife River had under ownership or lease, deposits of approximately 10.1 million tons of recoverable lignite coal.

Environmental Matters Knife River's construction materials and contracting operations are subject to regulation customary for such operations, including federal, state and local environmental compliance and reclamation regulations. Except as to what may be ultimately determined with regard to the Portland, Oregon, Harbor Superfund Site issue described later, Knife River believes it is in substantial compliance with these regulations.

Knife River's asphalt and ready-mixed concrete manufacturing plants and aggregate processing plants are subject to Clean Air Act and Clean Water Act requirements for controlling air emissions and water discharges. Some mining and construction activities also are subject to these laws. In most of the states where Knife River operates, these regulatory programs have been delegated to state and local regulatory authorities. Knife River's facilities also are subject to RCRA as it applies to the management of hazardous wastes and underground storage tank systems. These programs also have generally been delegated to the state and local authorities in the states where Knife River operates. No specific permits are required but Knife River's facilities must comply with requirements for managing wastes and underground storage tank systems.

Some Knife River activities are directly regulated by federal agencies. For example, gravel bar skimming and deep water dredging operations are subject to provisions of the Clean Water Act that are administered by the Army Corps. Knife River operates gravel bar skimming operations and deep water dredging operations in Oregon, all of which are subject to joint permits with the Army Corps and Oregon Department of State Lands. The expiration dates of these permits vary, with five years generally being the longest term. None of these in-water mining operations are included in Knife River's aggregate reserve numbers.

Knife River's operations also are occasionally subject to the ESA. For example, land use regulations often require environmental studies, including wildlife studies, before a permit may be granted for a new or expanded mining facility or an asphalt or concrete plant. If endangered species or their habitats are identified, ESA requirements for protection, mitigation or avoidance apply. Endangered species protection requirements are usually included as part of land use permit conditions. Typical conditions include avoidance, setbacks, restrictions on operations during certain times of the breeding or rearing season, and construction or purchase of mitigation habitat. Knife River's operations also are subject to state and federal cultural resources protection laws when new areas are disturbed for mining operations or processing plants. Land use permit applications generally require that areas proposed for mining or other surface disturbances be surveyed for cultural resources. If any are identified, they must be protected or managed in accordance with regulatory agency requirements.

The most comprehensive environmental permit requirements are usually associated with new mining operations, although requirements vary widely from state to state and even within states. In some areas, land use regulations and associated permitting requirements are minimal. However, some states and local jurisdictions have very demanding requirements for permitting new mines. Environmental impact reports are sometimes required before a mining permit application can even be considered for approval. These reports can take up to several years to complete. The report can include projected impacts of the proposed project on air and water quality, wildlife, noise levels, traffic, scenic vistas and other environmental factors. The reports generally include suggested actions to mitigate the projected adverse impacts.

Provisions for public hearings and public comments are usually included in land use permit application review procedures in the counties where Knife River operates. After taking into account environmental, mine plan and reclamation information provided by the permittee as well as comments from the public and other regulatory agencies, the local authority approves or denies the permit application. Denial is rare but land use permits often include conditions that must be addressed by the permittee. Conditions may include property line setbacks, reclamation requirements, environmental monitoring and reporting, operating hour restrictions, financial guarantees for reclamation, and other requirements intended to protect the environment or address concerns submitted by the public or other regulatory agencies.

Knife River has been successful in obtaining mining and other land use permit approvals so that sufficient permitted reserves are available to support its operations. For mining operations, this often requires considerable advanced planning to ensure sufficient time is available to complete the permitting process before the newly permitted aggregate reserve is needed to support Knife River's operations.

Knife River's Gascoyne surface coal mine last produced coal in 1995 but continues to be subject to reclamation requirements of the SMCRA, as well as the North Dakota Surface Mining Act. Portions of the Gascoyne Mine remain under reclamation bond until the 10-year revegetation liability period has expired. A portion of the original permit has been released from bond and additional areas are currently in the process of having the bond released. Knife River's intention is to request bond release as soon as it is deemed possible with all final bond release applications being filed by 2013.

Knife River did not incur any material environmental expenditures in 2007 and, except as to what may be ultimately determined with regard to the issue described below, Knife River does not expect to incur any material expenditures related to environmental compliance with current laws and regulations through 2010.

In December 2000, MBI was named by the EPA as a Potentially Responsible Party in connection with the cleanup of a commercial property site, acquired by MBI in 1999, and part of the Portland, Oregon, Harbor Superfund Site. For additional information, see Item 8 – Note 20.

ITEM 1A. RISK FACTORS

The Company's business and financial results are subject to a number of risks and uncertainties, including those set forth below and in other documents that it files with the SEC. The factors and the other matters discussed herein are important factors that could cause actual results or outcomes for the Company to differ materially from those discussed in the forward-looking statements included elsewhere in this document.

Economic Risks

The Company's natural gas and oil production and pipeline and energy services businesses are dependent on factors, including commodity prices and commodity price basis differentials, which are subject to various external influences that cannot be controlled.

These factors include: fluctuations in natural gas and crude oil prices; fluctuations in commodity price basis differentials; availability of economic supplies of natural gas; drilling successes in natural gas and oil operations; the timely receipt of necessary permits and approvals; the ability to contract for or to secure necessary drilling rig and service contracts and to retain employees to drill for and develop reserves; the ability to acquire natural gas and oil properties; and other risks incidental to the operations of natural gas and oil wells. Significant changes in these factors could negatively affect the results of operations, financial condition and cash flows of the Company's natural gas and oil production and pipeline and energy services businesses.

The construction, startup and operation of power generation facilities may involve unanticipated changes or delays that could negatively impact the Company's business, its results of operations and cash flows.

The construction, startup and operation of power generation facilities involves many risks, including: delays; breakdown or failure of equipment; competition; inability to obtain required governmental permits and approvals;

inability to negotiate acceptable acquisition, construction, fuel supply, off-take, transmission or other material agreements; changes in market price for power; cost increases; as well as the risk of performance below expected levels of output or efficiency. Such unanticipated events could negatively impact the Company's business, its results of operations and cash flows.

Economic volatility affects the Company's operations, as well as the demand for its products and services and, as a result, may have a negative impact on the Company's future revenues and cash flows.

The global demand for natural resources, interest rates, governmental budget constraints and the ongoing threat of terrorism can create volatility in the financial markets. A soft economy could negatively affect the level of public and private expenditures on projects and the timing of these projects which, in turn, would negatively affect the demand for the Company's products and services.

The construction materials and contracting segment is experiencing a reduction in construction activity and product sales volumes in some markets due to lower demand, which could negatively affect the Company's results of operations and cash flows.

The Company relies on financing sources and capital markets. If the Company is unable to obtain economic financing in the future, the Company's ability to execute its business plans, make capital expenditures or pursue acquisitions that the Company may otherwise rely on for future growth could be impaired.

The Company relies on access to both short-term borrowings, including the issuance of commercial paper, and long-term capital markets as sources of liquidity for capital requirements not satisfied by its cash flow from operations. If the Company is not able to access capital at competitive rates, the ability to implement its business plans may be adversely affected. Market disruptions or a downgrade of the Company's credit ratings may increase the cost of borrowing or adversely affect its ability to access one or more financial markets. Such disruptions could include:

- A severe prolonged economic downturn
- The bankruptcy of unrelated industry leaders in the same line of business
- A deterioration in capital market conditions
- Volatility in commodity prices
- Terrorist attacks

Actual quantities of recoverable natural gas and oil reserves and discounted future net cash flows from those reserves may vary significantly from estimated amounts.

The process of estimating natural gas and oil reserves is complex. Reserve estimates are based on assumptions relating to natural gas and oil pricing, drilling and operating expenses, capital expenditures, taxes, timing of operations, and the percentage of interest owned by the Company in the well. The reserve estimates are prepared for each of our properties by internal engineers assigned to an asset team by geographic area. The internal engineers analyze available geological, geophysical, engineering and economic data for each geographic area. The internal engineers make various assumptions regarding this data. The extent, quality and reliability of this data can vary. Although we have prepared our reserve estimates in accordance with guidelines established by the industry and the SEC, significant changes to the reserve estimates may occur based on actual results of production, drilling, costs and pricing.

In accordance with SEC requirements, we base the estimated discounted future net cash flows from proved reserves on prices and costs on the date of the estimate. Actual future prices and costs may be significantly different.

Environmental and Regulatory Risks

Some of the Company's operations are subject to extensive environmental laws and regulations that may increase costs of operations, impact or limit business plans, or expose the Company to environmental liabilities.

The Company is subject to extensive environmental laws and regulations affecting many aspects of its present and future operations including air quality, water quality, waste management and other environmental considerations. These laws and regulations can result in increased capital, operating and other costs, and delays as a result of ongoing litigation and administrative proceedings and compliance, remediation, containment and monitoring obligations, particularly with regard to laws relating to power plant emissions and CBNG development. These laws and regulations generally require the Company to obtain and comply with a wide variety of environmental licenses, permits, inspections and other approvals. Public officials and entities, as well as private individuals and organizations, may seek injunctive relief or other remedies to enforce applicable environmental laws and regulations. The Company cannot predict the outcome (financial or operational) of any related litigation or administrative proceedings that may arise. Existing environmental regulations may be revised and new regulations seeking to protect the environment may be adopted or become applicable to the Company. Revised or additional regulations, which result in increased compliance costs or additional operating restrictions, particularly if those costs are not fully recoverable from customers, could have a material adverse effect on the Company's results of operations and cash flows.

One of the Company's subsidiaries is subject to ongoing litigation and administrative proceedings in connection with its CBNG development activities. These proceedings have caused delays in CBNG drilling activity, and the ultimate outcome of the actions could have a material negative effect on existing CBNG operations and/or the future development of its CBNG properties.

Fidelity has been named as a defendant in, and/or certain of its operations are or have been the subject of, more than a dozen lawsuits filed in connection with its CBNG development in the Powder River Basin in Montana and Wyoming. If the plaintiffs are successful in these lawsuits, the ultimate outcome of the actions could have a material negative effect on Fidelity's existing CBNG operations and/or the future development of its CBNG properties.

The BER in March 2006 issued a decision in a rulemaking proceeding, initiated by the NPRC, that amends the non-degradation policy applicable to water discharged in connection with CBNG operations. The amended policy includes additional limitations on factors deemed harmful, thereby restricting water discharges even further than under previous standards. Due in part to this amended policy, in May 2006, the Northern Cheyenne Tribe commenced litigation in Montana state court challenging two five-year water discharge permits that the Montana DEQ granted to Fidelity in February 2006 and which are critical to Fidelity's ability to manage water produced under present and future CBNG operations. If these permits are set aside, Fidelity's CBNG operations in Montana could be significantly and adversely affected.

The Company is subject to extensive government regulations that may delay and/or have a negative impact on its business and its results of operations and cash flows.

The Company is subject to regulation by federal, state and local regulatory agencies with respect to, among other things, allowed rates of return, financings, industry rate structures, and recovery of purchased power and purchased gas costs. These governmental regulations significantly influence the Company's operating environment and may affect its ability to recover costs from its customers. The Company is unable to predict the impact on operating results from the future regulatory activities of any of these agencies.

Changes in regulations or the imposition of additional regulations could have an adverse impact on the Company's results of operations and cash flows.

Risks Relating to Foreign Operations

The value of the Company's investments in foreign operations may diminish due to political, regulatory and economic conditions and changes in currency exchange rates in countries where the Company does business.

The Company is subject to political, regulatory and economic conditions and changes in currency exchange rates in foreign countries where the Company does business. Significant changes in the political, regulatory or economic environment in these countries could negatively affect the value of the Company's investments located in these countries. Also, since the Company is unable to predict the fluctuations in the foreign currency exchange rates, these fluctuations may have an adverse impact on the Company's results of operations and cash flows.

Other Risks
One of the Company's subsidiaries is engaged in litigation with a nonaffiliated natural gas producer that has been conducting drilling and production operations that the subsidiary believes is causing diversion and loss of quantities of storage gas from one of its storage reservoirs. If the subsidiary is not able to obtain relief through the courts or the regulatory process, its storage operations could be materially and adversely affected.

Williston Basin has filed suit in Montana Federal District Court seeking to recover unspecified damages from Anadarko and its wholly owned subsidiary, Howell, and to enjoin Anadarko and Howell's present and future production operations in and near the EBSR. Based on relevant information, including reservoir and well pressure data, Williston Basin believes that EBSR pressures have decreased and that the storage reservoir has lost gas and continues to lose gas as a result of Anadarko and Howell's drilling and production activities. In related litigation, Howell filed suit in Wyoming State District Court against Williston Basin asserting that it is entitled to produce any gas that might escape from Williston Basin's storage reservoir. Williston Basin has answered Howell's complaint and has asserted counterclaims. If Williston Basin is unable to obtain timely relief through the courts or regulatory process, its present and future gas storage operations, including its ability to meet its contractual storage and transportation obligations to customers, could be materially and adversely affected.

Weather conditions can adversely affect the Company's operations and revenues and cash flows.

The Company's results of operations can be affected by changes in the weather. Weather conditions directly influence the demand for electricity and natural gas, affect the price of energy commodities, affect the ability to perform services at the construction services and construction materials and contracting businesses and affect ongoing operation and maintenance and construction and drilling activities for the pipeline and energy services and natural gas and oil production businesses. In addition, severe weather can be destructive, causing outages, reduced natural gas and oil production, and/or property damage, which could require additional costs to be incurred. As a result, adverse weather conditions could negatively affect the Company's results of operations, financial condition and cash flows.

Competition is increasing in all of the Company's businesses.

All of the Company's businesses are subject to increased competition. Construction services' competition is based primarily on price and reputation for quality, safety and reliability. The construction materials products are marketed under highly competitive conditions and are subject to such competitive forces as price, service, delivery time and proximity to the customer. The electric utility and natural gas industries also are experiencing increased competitive pressures as a result of consumer demands, technological advances, increased natural gas prices and other factors. Pipeline and energy services competes with several pipelines for access to natural gas supplies and gathering, transportation and storage business. The natural gas and oil production business is subject to competition in the acquisition and development of natural gas and oil properties. The increase in competition could negatively affect the Company's results of operations, financial condition and cash flows.

Other factors that could impact the Company's businesses.

The following are other factors that should be considered for a better understanding of the financial condition of the Company. These other factors may impact the Company's financial results in future periods.

- Acquisition, disposal and impairments of assets or facilities

- Changes in operation, performance and construction of plant facilities or other assets
- Changes in present or prospective generation
- The availability of economic expansion or development opportunities
- Population growth rates and demographic patterns
- Market demand for, and/or available supplies of, energy- and construction-related products and services
- The cyclical nature of large construction projects at certain operations
- Changes in tax rates or policies
- Unanticipated project delays or changes in project costs, including related energy costs
- Unanticipated changes in operating expenses or capital expenditures
- Labor negotiations or disputes
- Inability of the various contract counterparties to meet their contractual obligations
- Changes in accounting principles and/or the application of such principles to the Company
- Changes in technology
- Changes in legal or regulatory proceedings
- The ability to effectively integrate the operations and the internal controls of acquired companies
- The ability to attract and retain skilled labor and key personnel
- Increases in employee and retiree benefit costs

ITEM 1B. UNRESOLVED COMMENTS

The Company has no unresolved comments with the SEC.

ITEM 3. LEGAL PROCEEDINGS

For information regarding legal proceedings of the Company, see Item 8 – Note 20.

ITEM 4. SUBMISSION OF MATTERS TO A VOTE OF SECURITY HOLDERS

No matters were submitted to a vote of security holders during the fourth quarter of 2007.

PART II

ITEM 5. MARKET FOR THE REGISTRANT'S COMMON EQUITY, RELATED STOCKHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES

The Company's common stock is listed on the New York Stock Exchange under the symbol "MDU." The price range of the Company's common stock as reported by The Wall Street Journal composite tape during 2007 and 2006 and dividends declared thereon were as follows:

	Common Stock Price (High)	Common Stock Price (Low)	Common Stock Dividends Per Share
2007			
First quarter	$29.00	$24.39	$.1350
Second quarter	31.79	27.40	.1350
Third quarter	30.40	24.64	.1450
Fourth quarter	28.69	25.89	.1450
			$.5600

2006			
First quarter	$24.53	$21.85	$.1267
Second quarter	24.99	22.53	.1267
Third quarter	25.40	22.25	.1350
Fourth quarter	27.04	22.29	.1350
			$.5234

Note: Common stock share amounts reflect the Company's three-for-two common stock split effected in July 2006.

As of December 31, 2007, the Company's common stock was held by approximately 15,400 stockholders of record.

ITEM 6. SELECTED FINANCIAL DATA

	2007	2006	2005	2004	2003	2002
Selected Financial Data						
Operating revenues (000's):						
Electric	$ 193,367	$ 187,301	$ 181,238	$ 178,803	$ 178,562	$ 162,616
Natural gas distribution	532,997	351,988	384,199	316,120	274,608	186,569
Construction services	1,103,215	987,582	687,125	426,821	434,177	458,660
Pipeline and energy services	447,063	443,720	477,311	354,164	250,897	163,466
Natural gas and oil production	514,854	483,952	439,367	342,840	264,358	203,595
Construction materials and contracting	1,761,473	1,877,021	1,604,610	1,322,161	1,104,408	962,312
Other	10,061	8,117	6,038	4,423	2,728	3,778
Intersegment eliminations	(315,134)	(335,142)	(375,965)	(272,199)	(191,105)	(114,249)
	$ 4,247,896	$ 4,004,539	$ 3,403,923	$ 2,673,133	$ 2,318,633	$ 2,026,747
Operating income (000's):						
Electric	$ 31,652	$ 27,716	$ 29,038	$ 26,776	$ 35,761	$ 33,915
Natural gas distribution	32,903	8,744	7,404	1,820	6,502	2,414
Construction services	75,511	50,651	28,171	(5,757)	12,885	13,980
Pipeline and energy services	58,026	57,133	43,507	29,570	37,064	40,118
Natural gas and oil production	227,728	231,802	230,383	178,897	118,347	85,555
	138,635	156,104	105,318	86,030	91,579	91,430

Construction materials and contracting												
Other		(7,335)		(9,075)		(5,298)		(3,954)		(1,228)		(1,111)
	$	557,120	$	523,075	$	438,523	$	313,382	$	300,910	$	266,301
Earnings on common stock (000's):												
Electric	$	17,700	$	14,401	$	13,940	$	12,790	$	16,950	$	15,780
Natural gas distribution		14,044		5,680		3,515		2,182		3,869		3,587
Construction services		43,843		27,851		14,558		(5,650)		6,170		6,371
Pipeline and energy services		31,408		32,126		22,867		13,806		19,852		20,099
Natural gas and oil production		142,485		145,657		141,625		110,779		70,767		53,192
Construction materials and contracting		77,001		85,702		55,040		50,707		54,261		48,702
Other		(4,380)		(4,324)		13,061		15,967		597		497
Earnings on common stock before income (loss) from discontinued operations and cumulative effect of accounting change		322,101		307,093		264,606		200,581		172,466		148,228
Income (loss) from discontinued operations, net of tax		109,334		7,979		9,792		5,801		9,730		(540)
Cumulative effect of accounting change		---		---		---		---		(7,589)		---
	$	431,435	$	315,072	$	274,398	$	206,382	$	174,607	$	147,688
Earnings per common share before discontinued operations and cumulative effect of												

accounting change - diluted	$ 1.76	$ 1.69	$ 1.47	$ 1.14	$ 1.02	$ .92
Discontinued operations, net of tax	.60	.05	.06	.03	.06	---
Cumulative effect of accounting change	---	---	---	---	(.04)	---
	$ 2.36	$ 1.74	$ 1.53	$ 1.17	$ 1.04	$ .92
Common Stock Statistics						
Weighted average common shares outstanding - diluted (000's)	182,902	181,392	179,490	176,117	168,690	160,295
Dividends per common share	$ .5600	$ .5234	$ .4934	$ .4667	$ .4400	$ .4177
Book value per common share	$ 13.80	$ 11.88	$ 10.43	$ 9.39	$ 8.44	$ 7.71
Market price per common share (year end)	$ 27.61	$ 25.64	$ 21.83	$ 17.79	$ 15.87	$ 11.47
Market price ratios:						
Dividend payout	24%	30%	32%	40%	43%	45%
Yield	2.1%	2.1%	2.3%	2.7%	2.9%	3.7%
Price/earnings ratio	11.7x	14.7x	14.3x	15.2x	15.4x	12.5x
Market value as a percent of book value	200.1%	215.8%	209.2%	189.4%	188.1%	148.8%
Profitability Indicators						
Return on average common equity	18.5%	15.6%	15.7%	13.2%	13.0%	12.5%
Return on average invested capital	13.1%	10.6%	10.8%	9.4%	8.9%	8.6%
Fixed charges coverage, including preferred dividends	6.4x	6.4x	6.6x	4.8x	4.6x	4.9x
General						

Total assets (000's)	$ 5,592,434	$ 4,903,474	$ 4,423,562	$ 3,733,521	$ 3,380,592	$ 2,996,921
Total debt (000's)	$ 1,310,163	$ 1,254,582	$ 1,206,510	$ 945,487	$ 967,096	$ 861,741
Redeemable preferred stock (000's)	$ ---	$ ---	$ ---	$ ---	$ ---	$ 1,300
Capitalization ratios:						
Common equity	66%	63%	61%	63%	59%	59%
Preferred stocks	---	---	---	1	1	1
Total debt	34	37	39	36	40	40
	100%	100%	100%	100%	100%	100%

NOTES:

- Common stock share amounts reflect the Company's three-for-two common stock splits effected in July 2006 and October 2003.
- Cascade, a natural gas distribution business, was acquired on July 2, 2007. For further information, see Item 8 – Note 2.

	2007	2006	2005	2004	2003	2002
Electric						
Retail sales (thousand kWh)	2,601,649	2,483,248	2,413,704	2,303,460	2,359,888	2,275,024
Sales for resale (thousand kWh)	165,639	483,944	615,220	821,516	841,637	784,530
Electric system summer generating and firm purchase capability - kW (Interconnected system)	571,160	547,485	546,085	544,220	542,680	500,570
Demand peak – kW (Interconnected system)	525,643	485,456	470,470	470,470	470,470	458,800
Electricity produced (thousand kWh)	2,253,851	2,218,059	2,327,228	2,552,873	2,384,884	2,316,980
Electricity purchased (thousand kWh)	576,613	833,647	892,113	794,829	929,439	857,720
Average cost of fuel and purchased power per kWh	$ .025	$ .022	$ .020	$ .019	$ .019	$ .018
Natural Gas Distribution*						
Sales (Mdk)	52,977	34,553	36,231	36,607	38,572	39,558
Transportation (Mdk)	54,698	14,058	14,565	13,856	13,903	13,721
Weighted average degree days – % of previous year's actual						
Montana-Dakota	107%	95%	100%	94%	96%	109%
Cascade	101%	---	---	---	---	---
Pipeline and Energy Services						
Transportation (Mdk)	140,762	130,889	104,909	114,206	90,239	99,890
Gathering (Mdk)	92,414	87,135	82,111	80,527	75,861	72,692

Natural Gas and Oil Production						
Production:						
Natural gas (MMcf)	62,798	62,062	59,378	59,750	54,727	48,239
Oil (MBbls)	2,365	2,041	1,707	1,747	1,856	1,968
Average realized prices (including hedges):						
Natural gas (per Mcf)	$ 5.96	$ 6.03	$ 6.11	$ 4.69	$ 3.90	$ 2.72
Oil (per barrel)	$ 59.26	$ 50.64	$ 42.59	$ 34.16	$ 27.25	$ 22.80
Proved reserves:						
Natural gas (MMcf)	523,737	538,100	489,100	453,200	411,700	372,500
Oil (MBbls)	30,612	27,100	21,200	17,100	18,900	17,500
Construction Materials and Contracting						
Sales (000's):						
Aggregates (tons)	36,912	45,600	47,204	43,444	38,438	35,078
Asphalt (tons)	7,062	8,273	9,142	8,643	7,275	7,272
Ready-mixed concrete (cubic yards)	4,085	4,588	4,448	4,292	3,484	2,902
Recoverable aggregate reserves (tons)	1,215,253	1,248,099	1,273,696	1,257,498	1,181,413	1,110,020

* Cascade was acquired on July 2, 2007. For further information, see Item 8 – Note 2.

ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

OVERVIEW

The Company's strategy is to apply its expertise in energy and transportation infrastructure industries to increase market share, increase profitability and enhance shareholder value through:

- Organic growth as well as a continued disciplined approach to the acquisition of well-managed companies and properties
- The elimination of system-wide cost redundancies through increased focus on integration of operations and standardization and consolidation of various support services and functions across companies within the organization
  - The development of projects that are accretive to earnings per share and return on invested capital

The Company has capabilities to fund its growth and operations through various sources, including internally generated funds, commercial paper facilities and the issuance from time to time of debt securities and the Company's equity securities. For more information on the Company's net capital expenditures, see Liquidity and Capital Commitments.

The key strategies for each of the Company's business segments and certain related business challenges are summarized below. For a discussion of the Company's business segments, see Item 8 – Note ––16.

Key Strategies and Challenges

Electric and Natural Gas Distribution

Strategy Provide competitively priced energy to customers while working with them to ensure efficient usage. Both the electric and natural gas distribution segments continually seek opportunities for growth and expansion of their customer base through extensions of existing operations and through selected acquisitions of companies and properties at prices that will provide stable cash flows and an opportunity for the Company to earn a competitive return on investment. The natural gas distribution segment also continues to pursue growth by expanding its level of energy-related services.

Challenges Both segments are subject to extensive regulation in the state jurisdictions where they conduct operations with respect to costs and permitted returns on investment as well as subject to certain operational regulations at the federal level. The ability of these segments to grow through acquisitions is subject to significant competition from other energy providers. In addition, as to the electric business, the ability of this segment to grow its service territory and customer base is affected by significant competition from other energy providers, including rural electric cooperatives.

Construction Services
Strategy Provide a competitive return on investment while operating in a competitive industry by: building new and strengthening existing customer relationships; effectively controlling costs; retaining, developing and recruiting talented employees; focusing business development efforts on project areas that will permit higher margins; and properly managing risk. This segment continuously seeks opportunities to expand through strategic acquisitions.

Challenges This segment operates in highly competitive markets with many jobs subject to competitive bidding. Maintenance of effective operational and cost controls, retention of key personnel and managing through down turns in the economy are ongoing challenges.

Pipeline and Energy Services
Strategy Leverage the segment's existing expertise in energy infrastructure and related services to increase market share and profitability through optimization of existing operations, internal growth, and acquisitions of energy-related assets and companies. Incremental and new growth opportunities include: access to new sources of natural gas for storage, gathering and transportation services; expansion of existing gathering and transmission facilities; and incremental expansion of pipeline capacity to allow customers access to more liquid and higher-priced markets.

Challenges Energy price volatility; natural gas basis differentials; regulatory requirements; ongoing litigation; recruitment and retention of a skilled workforce; and increased competition from other natural gas pipeline and gathering companies.

Natural Gas and Oil Production
Strategy Apply technology and leverage existing exploration and production expertise, with a focus on operated properties, to increase production and reserves from existing leaseholds, and to seek additional reserves and production opportunities in new areas to further diversify the segment's asset base. By optimizing existing operations and taking advantage of new and incremental growth opportunities, this segment's goal is to increase both production and reserves over the long term so as to generate competitive returns on investment.

Challenges Fluctuations in natural gas and oil prices; ongoing environmental litigation and administrative proceedings; timely receipt of necessary permits and approvals; recruitment and retention of a skilled workforce; availability of drilling rigs, auxiliary equipment and industry-related field services; inflationary pressure on development and operating costs; and increased competition from other natural gas and oil companies.

Construction Materials and Contracting
Strategy Focus on high-growth strategic markets located near major transportation corridors and desirable mid-sized metropolitan areas; strengthen long-term, strategic aggregate reserve position through purchase and/or lease opportunities; enhance profitability through cost containment, margin discipline and vertical integration of the segment's operations; and continue growth through organic and acquisition opportunities. Ongoing efforts to increase margin are being pursued through the implementation of a variety of continuous improvement programs, including corporate purchasing of equipment, parts and commodities (liquid asphalt, diesel fuel, cement and other materials),

and negotiation of contract price escalation provisions. Vertical integration allows the segment to manage operations from aggregate mining to final lay-down of concrete and asphalt, with control of and access to adequate quantities of permitted aggregate reserves being significant. A key element of the Company's long-term strategy for this business is to further expand its presence, through acquisition, in the higher-margin materials business (rock, sand, gravel, liquid asphalt, ready-mixed concrete and related products), complementing and expanding on the Company's expertise.

Challenges Price volatility with respect to, and availability of, raw materials such as liquid asphalt, diesel fuel and cement; recruitment and retention of a skilled workforce; and management of fixed-price construction contracts, which are particularly vulnerable to volatility of these energy and material prices. The slowdown in the residential housing sector has adversely impacted operations. A greater emphasis on commercial, industrial, energy and public works projects and cost containment should partially mitigate the effects.

For further information on the risks and challenges the Company faces as it pursues its growth strategies and other factors that should be considered for a better understanding of the Company's financial condition, see Item 1A – Risk Factors. For further information on each segment's key growth strategies, projections and certain assumptions, see Prospective Information.

For information pertinent to various commitments and contingencies, see Item 8 – Notes to Consolidated Financial Statements.

Earnings Overview

The following table summarizes the contribution to consolidated earnings by each of the Company's businesses.

Years ended December 31,	2007	2006	2005
	(Dollars in millions, where applicable)		
Electric	$ 17.7	$ 14.4	$ 13.9
Natural gas distribution	14.0	5.7	3.5
Construction services	43.8	27.8	14.6
Pipeline and energy services	31.4	32.1	22.9
Natural gas and oil production	142.5	145.7	141.6
Construction materials and contracting	77.0	85.7	55.1
Other	(4.3)	(4.3)	13.0
Earnings before discontinued operations	322.1	307.1	264.6
Income from discontinued operations, net of tax	109.3	8.0	9.8
Earnings on common stock	$ 431.4	$ 315.1	$ 274.4
Earnings per common share – basic:			
Earnings before discontinued operations	$ 1.77	$ 1.70	$ 1.48
Discontinued operations, net of tax	.60	.05	.06
Earnings per common share – basic	$ 2.37	$ 1.75	$ 1.54
Earnings per common share – diluted:			
Earnings before discontinued operations	$ 1.76	$ 1.69	$ 1.47
Discontinued operations, net of tax	.60	.05	.06
Earnings per common share – diluted	$ 2.36	$ 1.74	$ 1.53
Return on average common equity	18.5%	15.6%	15.7%

2007 compared to 2006 Consolidated earnings for 2007 increased $116.3 million from the comparable period largely due to:

- Increased income from discontinued operations, net of tax, largely related to the gain on the sale of the Company's domestic independent power production assets and earnings related to an electric generating facility construction project

- Higher margins, workloads and equipment sales and rentals at the construction services business
- Increased earnings at the natural gas distribution business largely due to the acquisition of Cascade

Partially offsetting the increase were decreased earnings at the construction materials and contracting business, primarily related to decreased volumes and margins resulting from the slowdown in the residential housing sector.

Reflected in the Other category is the negative effect from an income tax adjustment of $9.4 million associated with the anticipated repatriation of profits from Brazilian operations as discussed in Item 8 – Note 15, partially offset by the gain of $6.1 million (after tax) related to the sale of Hartwell.

2006 compared to 2005 Consolidated earnings for 2006 increased $40.7 million from the comparable period largely due to:

- Higher earnings from construction, aggregate and asphalt operations, and earnings from companies acquired since the comparable prior period at the construction materials and contracting business
- Higher construction workloads and margins, as well as earnings from acquisitions made since the comparable prior period at the construction services business
- Higher transportation and gathering volumes, higher storage services revenue and higher gathering rates at the pipeline and energy services segment
- Increased oil and natural gas production of 20 percent and 5 percent, respectively, and higher average realized oil prices of 19 percent, partially offset by higher depreciation, depletion and amortization expense and higher lease operating expense at the natural gas and oil production business

Partially offsetting the increase were decreased earnings from equity method investments, which largely reflect the absence in 2006 of the 2005 $15.6 million benefit from the sale of the Termoceara Generating Facility reflected in the Other category.

FINANCIAL AND OPERATING DATA
Below are key financial and operating data for each of the Company's businesses.

Electric

Years ended December 31,	2007	2006	2005
	(Dollars in millions, where applicable)		
Operating revenues	$ 193.4	$ 187.3	$ 181.2
Operating expenses:			
Fuel and purchased power	69.6	67.4	63.6
Operation and maintenance	61.7	62.8	59.5
Depreciation, depletion and amortization	22.5	21.4	20.8
Taxes, other than income	7.9	8.0	8.3
	161.7	159.6	152.2
Operating income	31.7	27.7	29.0
Earnings	$ 17.7	$ 14.4	$ 13.9
Retail sales (million kWh)	2,601.7	2,483.2	2,413.7
Sales for resale (million kWh)	165.6	484.0	615.2
Average cost of fuel and purchased power per kWh	$ .025	$ .022	$ .020

2007 compared to 2006 Electric earnings increased $3.3 million (23 percent) compared to the prior year due to:

-

Higher retail sales margins, primarily due to lower demand charges related to a PPA that expired in the fourth quarter of 2006 and increased retail sales volumes of 5 percent
- Decreased operation and maintenance expense of $700,000 (after tax), primarily lower scheduled maintenance outage costs at electric generating stations

Partially offsetting the increase in earnings was lower sales for resale margins due to decreased volumes of 66 percent, largely due to a PPA that expired in the fourth quarter of 2006 and plant availability.

2006 compared to 2005 Electric earnings increased $500,000 (3 percent) compared to the prior year due to:

- Higher retail sales margins, primarily due to increased volumes of 3 percent and lower demand charges related to a PPA that expired in the fourth quarter of 2006
- Lower income taxes of $700,000
- Lower interest expense of $600,000 (after tax), resulting from lower average interest rates due to the purchase and redemption of certain higher cost long-term debt

Partially offsetting the increase in earnings were:

- Decreased sales for resale margins due to lower average rates of 15 percent and decreased volumes of 21 percent, largely due to plant availability
- Higher operation and maintenance expense of $1.7 million (after tax), primarily the result of scheduled maintenance outages at electric generating stations

Natural Gas Distribution

Years ended December 31,	2007	2006	2005
	(Dollars in millions, where applicable)		
Operating revenues	$ 533.0	$ 352.0	$ 384.2
Operating expenses:			
Purchased natural gas sold	372.2	259.5	315.4
Operation and maintenance	88.5	68.4	46.0
Depreciation, depletion and amortization	19.0	9.8	9.6
Taxes, other than income	20.4	5.6	5.8
	500.1	343.3	376.8
Operating income	32.9	8.7	7.4
Earnings	$ 14.0	$ 5.7	$ 3.5
Volumes (MMdk):			
Sales	53.0	34.5	36.2
Transportation	54.7	14.1	14.6
Total throughput	107.7	48.6	50.8
Degree days (% of normal)*			
Montana-Dakota	92.9%	86.7%	90.9%
Cascade	101.7%	---	---
Average cost of natural gas, including transportation, per dk**			
Montana-Dakota	$ 6.00	$ 7.51	$ 8.71
Cascade	$ 7.75	$ ---	$ ---

* Degree days are a measure of the daily temperature-related demand for energy for heating.

** Regulated natural gas sales only.

Note: Cascade was acquired on July 2, 2007. For further information, see Item 8 – Note 2.

2007 compared to 2006 The natural gas distribution business experienced an increase in earnings of $8.3 million (147 percent) compared to the prior year due to:

- Earnings of $5.8 million, including a third quarter seasonal loss, at Cascade which was acquired on July 2, 2007
- Increased nonregulated energy-related services of $1.3 million (after tax)
- Decreased operation and maintenance expense, excluding Cascade, of $800,000 (after tax), including the absence in 2007 of the 2006 early retirement program costs
- Increased retail sales volumes resulting from 7 percent colder weather than last year

2006 compared to 2005 The natural gas distribution business experienced an increase in earnings of $2.2 million (62 percent) compared to the prior year due to:

- Increased nonregulated earnings of $1.7 million (after tax) from energy-related services
- Lower income taxes of $900,000

Partially offsetting this increase were higher payroll-related expenses of $900,000 (after tax), largely due to an early retirement program.

The pass-through of lower natural gas prices is reflected in the decrease in both sales revenues and purchased natural gas sold. The decrease in sales revenues was partially offset by revenues from nonregulated energy-related services. Nonregulated energy-related services also contributed to the operation and maintenance expense increase.

Construction Services

Years ended December 31,	2007	2006	2005
		(In millions)	
Operating revenues	$ 1,103.2	$ 987.6	$ 687.1
Operating expenses:			
Operation and maintenance	979.7	892.7	625.1
Depreciation, depletion and amortization	14.3	15.4	13.4
Taxes, other than income	33.7	28.8	20.4
	1,027.7	936.9	658.9
Operating income	75.5	50.7	28.2
Earnings	$ 43.8	$ 27.8	$ 14.6

2007 compared to 2006 Construction services earnings increased $16.0 million (57 percent) due to:

- Higher construction margins and workloads of $13.1 million (after tax), largely in the Southwest and Central regions, including industrial-related work
- Increased equipment sales and rentals

2006 compared to 2005 Construction services earnings increased $13.2 million (91 percent) due to:

- Higher construction workloads and margins of $7.3 million (after tax), largely in the Southwest region
- Earnings from acquisitions made since the comparable prior period, which contributed approximately 43 percent of the earnings increase
- Higher equipment sales and rentals

Partially offsetting this increase were higher general and administrative expenses of $1.7 million (after tax), primarily payroll related.

Pipeline and Energy Services

Years ended December 31,	2007	2006	2005
	(Dollars in millions)		
Operating revenues	$ 447.1	$ 443.7	$ 477.3
Operating expenses:			
Purchased natural gas sold	291.7	311.0	363.7
Operation and maintenance	65.6	52.8	49.8
Depreciation, depletion and amortization	21.7	13.3	12.5
Taxes, other than income	10.1	9.5	7.8
	389.1	386.6	433.8
Operating income	58.0	57.1	43.5
Income from continuing operations	31.4	32.1	22.9
Income (loss) from discontinued operations, net of tax	.1	(2.1)	(.8)
Earnings	$ 31.5	$ 30.0	$ 22.1
Transportation volumes (MMdk):			
Montana-Dakota	29.3	31.0	31.4
Other	111.5	99.9	73.5
	140.8	130.9	104.9
Gathering volumes (MMdk)	92.4	87.1	82.1

2007 compared to 2006 Pipeline and energy services earnings increased $1.5 million (5 percent) due largely to:

- Higher transportation and gathering volumes ($5.4 million after tax)
- Increased income from discontinued operations of $2.2 million (after tax), related to Innovatum. For further information, see Item 8 – Note 3.
- Increased storage services revenue ($2.2 million after tax)
- Higher gathering rates ($1.4 million after tax)

Partially offsetting this increase in earnings were:

- Absence in 2007 of the benefit from the resolution of a rate proceeding of $4.1 million (after tax) recorded in 2006, which is reflected as a reduction to depreciation, depletion and amortization expense
- Higher operation and maintenance expense, largely due to the natural gas storage litigation and higher material costs. For further information regarding natural gas storage litigation, see Item 8 – Note 20.

The decrease in energy services revenues and purchased natural gas sold reflects the effect of lower natural gas prices.

2006 compared to 2005 Pipeline and energy services earnings increased $7.9 million (36 percent) due largely to:

- Higher transportation and gathering volumes ($5.3 million after tax)
- Higher storage services revenue ($5.8 million after tax)
- Higher gathering rates ($3.2 million after tax)

Partially offsetting this increase in earnings were:

- Absence in 2006 of the benefit from the resolution of a rate proceeding of $5.0 million (after tax) recorded in 2005, which was largely offset by the benefit from the resolution of a rate proceeding of $4.1 million (after tax) recorded in 2006, both of which included a reduction to depreciation, depletion and amortization expense.

- Higher operation and maintenance expense, primarily due to the natural gas storage litigation. For further information, see Item 8 - Note 20.
- An increased loss from discontinued operations of $1.3 million (after tax), related to Innovatum. For further information, see Item 8 – Note 3.

The decrease in energy services revenues and purchased natural gas sold reflects the effect of lower natural gas prices.

Natural Gas and Oil Production

Years ended December 31,	2007	2006	2005
	(Dollars in millions, where applicable)		
Operating revenues:			
Natural gas	$ 374.1	$ 373.9	$ 362.5
Oil	140.1	103.4	72.7
Other	.6	6.7	4.2
	514.8	484.0	439.4
Operating expenses:			
Purchased natural gas sold	.3	6.6	4.3
Operation and maintenance:			
Lease operating costs	66.9	52.8	39.2
Gathering and transportation	20.4	18.3	14.1
Other	34.6	31.9	31.2
Depreciation, depletion and amortization	127.4	106.8	84.8
Taxes, other than income:			
Production and property taxes	36.7	35.2	34.8
Other	.8	.6	.6
	287.1	252.2	209.0
Operating income	227.7	231.8	230.4
Earnings	$ 142.5	$ 145.7	$ 141.6
Production:			
Natural gas (MMcf)	62,798	62,062	59,378
Oil (MBbls)	2,365	2,041	1,707
Average realized prices (including hedges):			
Natural gas (per Mcf)	$ 5.96	$ 6.03	$ 6.11
Oil (per Bbl)	$ 59.26	$ 50.64	$ 42.59
Average realized prices (excluding hedges):			
Natural gas (per Mcf)	$ 5.37	$ 5.62	$ 6.87
Oil (per Bbl)	$ 59.53	$ 51.73	$ 48.73
Depreciation, depletion and amortization rate, per equivalent Mcf	$ 1.59	$ 1.38	$ 1.19
Production costs, including taxes, per equivalent Mcf:			
Lease operating costs	$ .87	$ .71	$ .56
Gathering and transportation	.26	.25	.20
Production and property taxes	.48	.47	.50
	$ 1.61	$ 1.43	$ 1.26

2007 compared to 2006 The natural gas and oil production business experienced a decrease in earnings of $3.2 million (2 percent) due to:

- Increased depreciation, depletion and amortization expense of $12.8 million (after tax) due to higher depletion rates and increased production

- Higher lease operating costs of $8.8 million (after tax), largely CBNG-related and costs related to acquired properties, as well as increased service-related costs
- Lower average realized natural gas prices of 1 percent
- Increased general and administrative expense of $1.9 million (after tax)

Partially offsetting the decrease were:

- Increased oil production of 16 percent resulting from the May 2006 Big Horn acquisition, as well as from the South Texas properties
- Higher average realized oil prices of 17 percent
- Increased natural gas production of 1 percent

2006 compared to 2005 The natural gas and oil production business experienced an increase in earnings of $4.1 million (3 percent) due to:

- Increased oil production of 20 percent and natural gas production of 5 percent, largely due to the May 2005 South Texas and May 2006 Big Horn acquisitions and increased production in the Rocky Mountain region
- Higher average realized oil prices of 19 percent

Partially offsetting the increase were:

- Higher depreciation, depletion and amortization expense of $13.5 million (after tax) due to higher depletion rates and increased production
- Higher lease operating expense of $8.4 million (after tax), largely acquisition and CBNG-related costs

Construction Materials and Contracting

Years ended December 31,	2007	2006	2005
	(Dollars in millions)		
Operating revenues	$ 1,761.5	$ 1,877.0	$ 1,604.6
Operating expenses:			
Operation and maintenance	1,483.5	1,593.7	1,381.9
Depreciation, depletion and amortization	95.8	88.7	78.0
Taxes, other than income	43.6	38.5	39.4
	1,622.9	1,720.9	1,499.3
Operating income	138.6	156.1	105.3
Earnings	$ 77.0	$ 85.7	$ 55.1
Sales (000's):			
Aggregates (tons)	36,912	45,600	47,204
Asphalt (tons)	7,062	8,273	9,142
Ready-mixed concrete (cubic yards)	4,085	4,588	4,448

2007 compared to 2006 Earnings at the construction materials and contracting business decreased $8.7 million (10 percent) due to:

- Decreased earnings of $14.2 million (after tax) from construction, primarily related to the slowdown in the residential housing sector
- Lower earnings from ready-mixed concrete and aggregate operations of $13.8 million (after tax), due to lower volumes and margins related to the slowdown in the residential housing sector

Partially offsetting the decrease were:

- Increased earnings from asphalt and related products of $9.1 million (after tax), due to higher margins
- Decreased general and administrative expense of $5.6 million (after tax), including lower payroll-related costs
- Earnings from companies acquired since the comparable prior period, which contributed approximately 3 percent of earnings for 2007

2006 compared to 2005 Earnings at the construction materials and contracting business increased $30.6 million (56 percent) due to:

- Higher earnings of $18.8 million (after tax) from construction, largely due to increased volumes and margins, the result of strong markets and improvements in Texas
- Increased earnings from aggregate and asphalt operations of $10.4 million (after tax), largely due to higher realized margins, partially offset by lower volumes
- Earnings from companies acquired since the comparable prior period, which contributed approximately 18 percent of the earnings increase
- Higher earnings of $4.2 million (after tax) from ready-mixed concrete operations, largely due to higher margins

Partially offsetting the increase were:

- Higher depreciation, depletion and amortization expense from existing operations of $4.6 million (after tax), primarily due to higher property, plant and equipment balances
- Increased general and administrative expense of $4.2 million (after tax), primarily payroll-related

Other and Intersegment Transactions

Amounts presented in the preceding tables will not agree with the Consolidated Statements of Income due to the Company's other operations and the elimination of intersegment transactions. The amounts relating to these items are as follows:

Years ended December 31,	2007	2006	2005
		(In millions)	
Other:			
Operating revenues	$ 10.0	$ 8.1	$ 6.0
Operation and maintenance	15.9	15.4	10.7
Depreciation, depletion and amortization	1.2	1.2	.3
Taxes, other than income	.2	.6	.3
Intersegment transactions:			
Operating revenues	$ 315.1	$ 335.1	$ 375.9
Purchased natural gas sold	286.8	308.1	354.2
Operation and maintenance	28.3	27.0	21.7

For further information on intersegment eliminations, see Item 8 – Note 16.

PROSPECTIVE INFORMATION

The following information highlights the key growth strategies, projections and certain assumptions for the Company and its subsidiaries and other matters for each of the Company's businesses. Many of these highlighted points are "forward-looking statements." There is no assurance that the Company's projections, including estimates for growth and changes in earnings, will in fact be achieved. Please refer to assumptions contained in this section as well as the various important factors listed in Item 1A – Risk Factors. Changes in such assumptions and factors could cause actual future results to differ materially from the Company's targeted growth and earnings projections.

MDU Resources Group, Inc.

- Earnings per common share for 2008, diluted, are projected in the range of $1.65 to $1.90.

- The Company expects the percentage of 2008 earnings per common share, diluted, by quarter to be in the following approximate ranges:
  - First quarter – 15 percent to 20 percent
  - Second quarter – 20 percent to 25 percent
  - Third quarter – 30 percent to 35 percent
  - Fourth quarter – 25 percent to 30 percent

- Long-term compound annual growth goals on earnings per share from operations are in the range of 7 percent to 10 percent.

Electric

- The Company is analyzing potential projects for accommodating load growth and replacing an expired purchased power contract with company-owned generation, which will add to base-load capacity and rate base. A final decision on the Big Stone Station II project will be made when major permits are issued and certain regulatory approvals are obtained, which is expected by mid-to-late 2008. The plant is projected to be completed in 2013. The Company anticipates it would own at least 116 MW of this plant or other generation sources. For further information, see Item 8 – Note 19.

- On July 12, 2007, Montana-Dakota filed an electric rate case with the MTPSC, as discussed in Item 8 – Note 19.

- This business continues to pursue expansion of energy-related services.

Natural gas distribution

- This business continues to pursue expansion of energy-related services and expects continued strong customer growth in Washington and Oregon.

Construction services

- The Company anticipates margins in 2008 to be slightly lower than 2007.

- The Company continues to focus on costs and efficiencies to enhance margins.

Pipeline and energy services

- Based on anticipated demand, incremental expansions to the Grasslands Pipeline are forecasted over the next few years. Through additional compression, the pipeline firm capacity could ultimately reach 200,000 Mcf per day, an increase from the current firm capacity of 138,000 Mcf per day.

- In 2008, total gathering and transportation throughput is expected to be slightly higher than 2007 record levels.

Natural gas and oil production

- The Company expects a combined natural gas and oil production increase in 2008 in the range of 12 percent to 16 percent over 2007 levels, including the effects of the acquisition of natural gas production assets in East Texas. Meeting these targets will depend on the timely receipt of regulatory approvals and the success of exploration activities.

- The Company expects to participate in more than 375 wells in 2008. Specifically, in the Rocky Mountain Region, the Company expects to drill approximately 240 operated wells (approximately 195 net wells) in the Baker, Bowdoin, Powder River Basin and Big Horn Basin areas, and to participate in 30 or more wells in the Bakken and Paradox Basin areas, dependent upon success. Also included in the 375 wells are 25 wells to further develop the properties associated with the acquisition of natural gas production assets in East Texas.

- Currently, this segment's net combined natural gas and oil production is approximately 225,000 Mcf equivalents to 240,000 Mcf equivalents per day, which includes the recently acquired East Texas properties.

- The Company is pursuing exploratory drilling in the Bakken play in North Dakota and the Paradox Basin in Utah. Its acreage position in the Bakken play includes approximately 75,000 net acres in Mountrail and Burke counties. The first of its operated wells in the Bakken play is scheduled for completion in February. The Company’s first well in the Paradox Basin began producing in mid-November. The Company owns approximately 57,000 net acres in the Paradox Basin.

- The Company is pursuing continued reserve growth through the further exploitation of its existing properties, exploratory drilling and acquisitions of properties.

- Earnings guidance reflects estimated natural gas prices for February through December 2008 as follows:

Index*	Price Per Mcf
Ventura	$6.75 to $7.25
NYMEX	$7.25 to $7.75
CIG	$5.50 to $6.00

* Ventura is an index pricing point related to Northern Natural Gas Co.’s system; CIG is an index pricing point related to Colorado Interstate Gas Co.’s system.

During 2007, more than three-fourths of natural gas production was priced at non-NYMEX prices, the majority of which was at Ventura pricing.

- Earnings guidance reflects estimated NYMEX crude oil prices for February through December in the range of $75 to $80 per barrel.

- For 2008, the Company has hedged approximately 35 percent to 40 percent of its estimated natural gas production and less than 5 percent of its estimated oil production. Of its estimated natural gas production, the Company has hedged approximately 15 percent to 20 percent for 2009, and less than 5 percent for 2010 and 2011. The hedges that are in place as of February 14, 2008, are summarized in the following chart:

Commodity	Index*	Period Outstanding	Forward Notional Volume (MMBtu/Bbl)	Price Swap or Costless Collar Floor-Ceiling (Per MMBtu/Bbl)
Natural Gas	Ventura	1/08 - 3/08	910,000	$8.00-$8.75
Natural Gas	Ventura	1/08 - 3/08	364,000	$9.01
Natural Gas	Ventura	1/08 - 3/08	910,000	$9.35
Natural Gas	CIG	1/08 - 3/08	910,000	$7.00-$7.79
Natural Gas	CIG	1/08 - 3/08	910,000	$8.06
Natural Gas	Ventura	4/08 - 10/08	1,070,000	$7.00-$8.05
Natural Gas	Ventura	4/08 - 10/08	1,070,000	$7.00-$8.06
Natural Gas	Ventura	4/08 - 10/08	1,070,000	$7.45
Natural Gas	Ventura	4/08 - 10/08	1,070,000	$7.50-$8.70
Natural Gas	Ventura	4/08 - 10/08	1,070,000	$8.005
Natural Gas	Ventura	4/08 - 10/08	749,000	$7.25-$8.02
Natural Gas	CIG	4/08 - 10/08	749,000	$5.75-$7.40

Natural Gas	Ventura	1/08 - 12/08	1,830,000	$7.00-$8.45
Natural Gas	Ventura	1/08 - 12/08	1,830,000	$7.50-$8.34
Natural Gas	Ventura	1/08 - 12/08	3,294,000	$8.55
Natural Gas	NYMEX	1/08 - 12/08	1,830,000	$7.50-$10.15
Natural Gas	HSC	3/08 - 12/08	2,080,800	$7.91
Natural Gas	CIG	4/08 - 12/08	1,375,000	$6.75-$7.04
Natural Gas	CIG	4/08 - 12/08	1,375,000	$6.35
Natural Gas	CIG	4/08 - 12/08	1,375,000	$6.41
Natural Gas	Ventura	11/08 - 12/08	427,000	$9.25
Natural Gas	Ventura	11/08 - 12/08	610,000	$8.85
Natural Gas	CIG	1/09 - 3/09	225,000	$8.45
Natural Gas	HSC	1/09 - 12/09	2,482,000	$8.16
Natural Gas	Ventura	1/09 - 12/09	1,460,000	$7.90-$8.54
Natural Gas	Ventura	1/09 - 12/09	4,380,000	$8.25-$8.92
Natural Gas	CIG	1/09 - 12/09	3,650,000	$6.50-$7.20
Natural Gas	CIG	1/09 - 12/09	912,500	$7.27
Natural Gas	HSC	1/10 - 12/10	1,606,000	$8.08
Natural Gas	HSC	1/11 - 12/11	1,350,500	$8.00
Crude Oil	NYMEX	1/08 - 12/08	73,200	$67.50-$78.70

* Ventura is an index pricing point related to Northern Natural Gas Co.'s system; CIG is an index pricing point related to Colorado Interstate Gas Co.'s system; HSC is the Houston Ship Channel hub in southeast Texas which connects to several pipelines.

Construction materials and contracting

- The slow down in the residential housing sector has adversely impacted operations. A greater emphasis on commercial, industrial, energy and public works projects and cost containment should partially mitigate the effects.

NEW ACCOUNTING STANDARDS

For information regarding new accounting standards, see Item 8 – Note 1, which is incorporated by reference.

CRITICAL ACCOUNTING POLICIES INVOLVING SIGNIFICANT ESTIMATES

The Company has prepared its financial statements in conformity with accounting principles generally accepted in the United States of America. The preparation of these financial statements requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities, and disclosure of contingent assets and liabilities, at the date of the financial statements as well as the reported amounts of revenues and expenses during the reporting period. The Company's significant accounting policies are discussed in Item 8 – Note 1.

Estimates are used for items such as impairment testing of long-lived assets, goodwill and natural gas and oil properties; fair values of acquired assets and liabilities under the purchase method of accounting; natural gas and oil reserves; aggregate reserves; property depreciable lives; tax provisions; uncollectible accounts; environmental and other loss contingencies; accumulated provision for revenues subject to refund; costs on construction contracts; unbilled revenues; actuarially determined benefit costs; asset retirement obligations; the valuation of stock-based compensation; and the fair value of derivative instruments. The Company's critical accounting policies are subject to judgments and uncertainties that affect the application of such policies. As discussed below, the Company's financial position or results of operations may be materially different when reported under different conditions or when using different assumptions in the application of such policies.

As additional information becomes available, or actual amounts are determinable, the recorded estimates are revised. Consequently, operating results can be affected by revisions to prior accounting estimates. The following critical accounting policies involve significant judgments and estimates.

Impairment of long-lived assets and intangibles
The Company reviews the carrying values of its long-lived assets and intangibles, excluding natural gas and oil properties, whenever events or changes in circumstances indicate that such carrying values may not be recoverable and annually for goodwill. Unforeseen events and changes in circumstances and market conditions and material differences in the value of long-lived assets and intangibles due to changes in estimates of future cash flows could negatively affect the fair value of the Company's assets and result in an impairment charge. If an impairment indicator exists for tangible and intangible assets, excluding goodwill, the asset group held and used is tested for recoverability by comparing an estimate of undiscounted future cash flows attributable to the assets compared to the carrying value of the assets. If impairment has occurred, the amount of the impairment recognized is determined by estimating the fair value of the assets and recording a loss if the carrying value is greater than the fair value. In the case of goodwill, the first step, used to identify a potential impairment, compares the fair value of the reporting unit using discounted cash flows, with its carrying amount, including goodwill. The second step, used to measure the amount of the impairment loss if step one indicates a potential impairment, compares the implied fair value of the reporting unit goodwill with the carrying amount of goodwill.

Fair value is the amount at which the asset could be bought or sold in a current transaction between willing parties. The Company uses critical estimates and assumptions when testing assets for impairment, including present value techniques based on estimates of cash flows, quoted market prices or valuations by third parties, or multiples of earnings or revenue performance measures. The fair value of the asset could be different using different estimates and assumptions in these valuation techniques.

There is risk involved when determining the fair value of assets, tangible and intangible, as there may be unforeseen events and changes in circumstances and market conditions and changes in estimates of future cash flows.

The Company believes its estimates used in calculating the fair value of long-lived assets, including goodwill and identifiable intangibles, are reasonable based on the information that is known when the estimates are made.

Natural gas and oil properties
The Company uses the full-cost method of accounting for its natural gas and oil production activities. Capitalized costs are subject to a "ceiling test" that limits such costs to the aggregate of the present value of future net revenues of proved reserves based on single point-in-time spot market prices, as mandated under the rules of the SEC, plus the cost of unproved properties. Judgments and assumptions are made when estimating and valuing reserves. There is risk that sustained downward movements in natural gas and oil prices, changes in estimates of reserve quantities and changes in operating and development costs could result in a future noncash write-down of the Company's natural gas and oil properties.

Estimates of reserves are arrived at using actual historical wellhead production trends and/or standard reservoir engineering methods utilizing available engineering and geologic data derived from well tests. Other factors used in the reserve estimates are current natural gas and oil prices, current estimates of well operating and future development costs, and the interest owned by the Company in the well. These estimates are refined as new information becomes available.

Historically, the Company has not had any material revisions to its reserve estimates. As a result, the Company has not changed its practice in estimating reserves and does not anticipate changing its methodologies in the future.

Revenue recognition
Revenue is recognized when the earnings process is complete, as evidenced by an agreement between the customer and the Company, when delivery has occurred or services have been rendered, when the fee is fixed or determinable and when collection is reasonably assured. The recognition of revenue in conformity with accounting principles

generally accepted in the United States of America requires the Company to make estimates and assumptions that affect the reported amounts of revenue. Critical estimates related to the recognition of revenue include the accumulated provision for revenues subject to refund and costs on construction contracts under the percentage-of-completion method.

Estimates for revenues subject to refund are established initially for each regulatory rate proceeding and are subject to change depending on the applicable regulatory agency's (Agency) approval of final rates. These estimates are based on the Company's analysis of its as-filed application compared to previous Agency decisions in prior rate filings by the Company and other regulated companies. The Company periodically reviews the status of its outstanding regulatory proceedings and liability assumptions and may from time to time change its liability estimates subject to known developments as the regulatory proceedings move through the regulatory review process. The accuracy of the estimates is ultimately determined when the Agency issues its final ruling on each regulatory proceeding for which revenues were subject to refund. Estimates have changed from time to time as additional information has become available as to what the ultimate outcome may be and will likely continue to change in the future as new information becomes available on each outstanding regulatory proceeding that is subject to refund.

The Company recognizes construction contract revenue from fixed-price and modified fixed-price construction contracts at its construction businesses using the percentage-of-completion method, measured by the percentage of costs incurred to date to estimated total costs for each contract. This method depends largely on the ability to make reasonably dependable estimates related to the extent of progress toward completion of the contract, contract revenues and contract costs. Inasmuch as contract prices are generally set before the work is performed, the estimates pertaining to every project could contain significant unknown risks such as volatile labor, material and fuel costs, weather delays, adverse project site conditions, unforeseen actions by regulatory agencies, performance by subcontractors, job management and relations with project owners.

Several factors are evaluated in determining the bid price for contract work. These include, but are not limited to, the complexities of the job, past history performing similar types of work, seasonal weather patterns, competition and market conditions, job site conditions, work force safety, reputation of the project owner, availability of labor, materials and fuel, project location and project completion dates. As a project commences, estimates are continually monitored and revised as information becomes available and actual costs and conditions surrounding the job become known.

The Company believes its estimates surrounding percentage-of-completion accounting are reasonable based on the information that is known when the estimates are made. The Company has contract administration, accounting and management control systems in place that allow its estimates to be updated and monitored on a regular basis. Because of the many factors that are evaluated in determining bid prices, it is inherent that the Company's estimates have changed in the past and will continually change in the future as new information becomes available for each job.

Purchase accounting

The Company accounts for its acquisitions under the purchase method of accounting and, accordingly, the acquired assets and liabilities assumed are recorded at their respective fair values. The excess of the purchase price over the fair value of the assets acquired and liabilities assumed is recorded as goodwill. The recorded values of assets and liabilities are based on third-party estimates and valuations when available. The remaining values are based on management's judgments and estimates, and, accordingly, the Company's financial position or results of operations may be affected by changes in estimates and judgments.

Acquired assets and liabilities assumed by the Company that are subject to critical estimates include property, plant and equipment and intangibles.

The fair value of owned recoverable aggregate reserve deposits is determined using qualified internal personnel as well as geologists. Reserve estimates are calculated based on the best available data. This data is collected from drill holes and other subsurface investigations as well as investigations of surface features such as mine highwalls and other exposures of the aggregate reserves. Mine plans, production history and geologic data are also used to estimate reserve quantities. Value is assigned to the aggregate reserves based on a review of market royalty rates, expected cash flows and the number of years of recoverable aggregate reserves at owned aggregate sites.

The fair value of property, plant and equipment is based on a valuation performed either by qualified internal personnel and/or outside appraisers. Fair values assigned to plant and equipment are based on several factors including the age and condition of the equipment, maintenance records of the equipment and auction values for equipment with similar characteristics at the time of purchase.

The fair value of leasehold rights is based on estimates including royalty rates, lease terms and other discernible factors for acquired leasehold rights, and estimated cash flows.

While the allocation of the purchase price of an acquisition is subject to a considerable degree of judgment and uncertainty, the Company does not expect the estimates to vary significantly once an acquisition has been completed. The Company believes its estimates have been reasonable in the past as there have been no significant valuation adjustments subsequent to the final allocation of the purchase price to the acquired assets and liabilities. In addition, goodwill impairment testing is performed annually in accordance with SFAS No. 142.

Asset retirement obligations

Entities are required to record the fair value of a liability for an asset retirement obligation in the period in which it is incurred. The Company has recorded obligations related to the plugging and abandonment of natural gas and oil wells, decommissioning of certain electric generating facilities, reclamation of certain aggregate properties, special handling and disposal of hazardous materials at certain electric generating facilities, natural gas distribution and transmission facilities and buildings and certain other obligations associated with leased properties.

The liability for future asset retirement obligations bears the risk of change as many factors go into the development of the estimate of these obligations and the likelihood that over time these factors can and will change. Factors used in the estimation of future asset retirement obligations include estimates of current retirement costs, future inflation factors, life of the asset and discount rates. These factors determine both a present value of the retirement liability and the accretion to the retirement liability in subsequent years.

Long-lived assets are reviewed to determine if a legal retirement obligation exists. If a legal retirement obligation exists, a determination of the liability is made if a reasonable estimate of the present value of the obligation can be made. The present value of the retirement obligation is calculated by inflating current estimated retirement costs of the long-lived asset over its expected life to determine the expected future cost and then discounting the expected future cost back to the present value using a discount rate equal to the credit-adjusted risk-free interest rate in effect when the liability was initially recognized.

These estimates and assumptions are subject to a number of variables and are expected to change in the future. Estimates and assumptions will change as the estimated useful lives of the assets change, the current estimated retirement costs change, new legal retirement obligations occur and/or as existing legal asset retirement obligations, for which a reasonable estimate of fair value could not initially be made because of the range of time over which the Company may settle the obligation is unknown or cannot be estimated, become less uncertain and a reasonable estimate of the future liability can be made.

Pension and other postretirement benefits

The Company has noncontributory defined benefit pension plans and other postretirement benefit plans for certain eligible employees. Various actuarial assumptions are used in calculating the benefit expense (income) and liability (asset) related to these plans. Costs of providing pension and other postretirement benefits bear the risk of change, as they are dependent upon numerous factors based on assumptions of future conditions.

The Company makes various assumptions when determining plan costs, including the current discount rates and the expected long-term return on plan assets, the rate of compensation increases and healthcare cost trend rates. In selecting the expected long-term return on plan assets, which is considered to be one of the key variables in determining benefit expense or income, the Company considers both current market conditions and expected future market trends, including changes in interest rates and equity and bond market performance. Another key variable in determining benefit expense or income is the discount rate. In selecting the discount rate, the Company uses the yield of a fixed-income debt security, which has a rating of "Aa" or higher published by a recognized rating agency, as well as other factors, as a basis. The Company's pension and other postretirement benefit plan assets are primarily made up of equity and fixed-income investments. Fluctuations in actual equity and bond market returns as well as changes in general interest rates may result in increased or decreased pension and other postretirement benefit costs in the future. Management estimates the rate of compensation increase based on long-term assumed wage increases and the healthcare cost trend rates are determined by historical and future trends.

The Company believes the estimates made for its pension and other postretirement benefits are reasonable based on the information that is known when the estimates are made. These estimates and assumptions are subject to a number of variables and are expected to change in the future. Estimates and assumptions will be affected by changes in the discount rate, the expected long-term return on plan assets, the rate of compensation increase and healthcare cost trend rates. The Company plans to continue to use its current methodologies to determine plan costs.

Income taxes

Income taxes require significant judgments and estimates including the determination of income tax expense, deferred tax assets and liabilities and, if necessary, any valuation allowances that may be required for deferred tax assets and accruals for uncertain tax positions. The effective income tax rate is subject to variability from period to period as a result of changes in federal and state income tax rates and/or changes in tax laws. In addition, the effective tax rate may be affected by other changes including the allocation of property, payroll and revenues between states.

The Company provides deferred federal and state income taxes on all temporary differences between the book and tax basis of the Company's assets and liabilities. Excess deferred income tax balances associated with the Company's rate-regulated activities resulting from the Company's adoption of SFAS No. 109 have been recorded as a regulatory liability and are included in other liabilities. These regulatory liabilities are expected to be reflected as a reduction in future rates charged to customers in accordance with applicable regulatory procedures.

The Company uses the deferral method of accounting for investment tax credits and amortizes the credits on electric and natural gas distribution plant over various periods that conform to the ratemaking treatment prescribed by the applicable state public service commissions.

On January 1, 2007, the Company adopted FIN 48 as discussed in Item 8 – Notes 1 and 15. FIN 48 clarifies the application of SFAS No. 109 by defining a criterion that an individual tax position must meet for any part of the benefit of that position to be recognized in an enterprise's financial statements. The criterion allows for recognition in the financial statements of a tax position when it is more likely than not that the position will be sustained upon examination.

The Company believes its estimates surrounding income taxes are reasonable based on the information that is known when the estimates are made.

LIQUIDITY AND CAPITAL COMMITMENTS

Cash flows

Operating activities Net income before depreciation, depletion and amortization is a significant contributor to cash flows from operating activities. The changes in cash flows from operating activities generally follow the results of operations as discussed in Financial and Operating Data and also are affected by changes in working capital.

Cash flows provided by operating activities in 2007 decreased $96.4 million from the comparable prior period, the result of:

- Increased cash flows used related to discontinued operations of $104.9 million, largely due to an increase in quarterly income tax payments due to the gain on the sale of the domestic independent power production assets
- Increased working capital requirements of $59.2 million, largely due to higher cash needs for receivables at the natural gas distribution business, including the effects of the acquisition of Cascade and fluctuations in natural gas prices

Partially offsetting the decrease in cash flows from operating activities were:

- Higher depreciation, depletion and amortization expense of $45.4 million, largely at the natural gas and oil production business
- Higher deferred income taxes of $28.6 million, largely related to expenditures at the natural gas and oil production business and the effect from an income tax adjustment associated with the anticipated repatriation of profits from Brazilian operations as discussed in Item 8 – Note 15.

Cash flows provided by operating activities in 2006 increased $176.0 million from the comparable 2005 period, the result of:

- Lower working capital requirements of $66.4 million, largely due to lower cash needs for receivables at the natural gas distribution, natural gas and oil production and construction services businesses
- Higher depreciation, depletion and amortization expense of $37.1 million largely at the natural gas and oil production and construction materials and contracting businesses
- Increased income from continuing operations of $42.5 million, largely increased earnings at the construction materials and contracting, construction services and pipeline and energy services businesses
- Decreased earnings, net of distributions, from equity method investments of $10.3 million, primarily the result of the sale of the Termoceara Generating Facility in 2005

Investing activities Cash flows used in investing activities in 2007 decreased $318.0 million compared to the comparable prior period, the result of:

- An increase in cash flows provided by discontinued operations of $586.1 million, primarily the result of the sale of the domestic independent power production assets in the third quarter of 2007
- Increased proceeds from the sale of equity method investments of $58.5 million, primarily the result of the sale of the Trinity Generating Facility in the first quarter of 2007 and Hartwell in the third quarter of 2007

Partially offsetting the decrease in cash flows used in investing activities were:

- An increase in cash flows used for acquisitions, net of cash acquired, of $234.7 million, largely the result of the Cascade acquisition
- Higher ongoing capital expenditures, including expenditures related to a wind electric generation project at the electric business

Cash flows used in investing activities in 2006 increased $16.3 million compared to the comparable 2005 period, the result of:

- Increased investments largely due to the acquisition of the Brazilian Transmission Lines
- The absence in 2006 of the 2005 proceeds from the sale of the Termoceara Generating Facility
-

Higher ongoing capital expenditures, primarily at the natural gas and oil production and construction materials and contracting businesses

Partially offsetting the increase was a decrease in cash flows used for:

- Acquisitions of $99.8 million, largely at the natural gas and oil production and construction materials and contracting businesses
    - Discontinued operations, due to lower capital expenditures related to the Hardin Generating Facility

Financing activities Cash flows used in financing activities in 2007 increased $158.4 million compared to the comparable prior period, primarily the result of a decrease in the issuance of long-term debt of $236.1 million, partially offset by lower repayments of long-term debt of $83.0 million. Also reflected in cash flows from financing activities was the issuance and subsequent repayment of short-term borrowings of $310.0 million from the term loan agreement entered into in connection with the funding of the Cascade acquisition.

Cash flows provided by financing activities in 2006 decreased $198.8 million compared to the comparable 2005 period, primarily the result of an increase in repayment of long-term debt of $208.7 million, partially offset by an increase in proceeds from the issuance of common stock of $10.8 million.

Defined benefit pension plans
The Company has qualified noncontributory defined benefit pension plans (Pension Plans) for certain employees. Plan assets consist of investments in equity and fixed-income securities. Various actuarial assumptions are used in calculating the benefit expense (income) and liability (asset) related to the Pension Plans. Actuarial assumptions include assumptions about the discount rate, expected return on plan assets and rate of future compensation increases as determined by the Company within certain guidelines. At December 31, 2007, certain Pension Plans' accumulated benefit obligations exceeded these plans' assets by approximately $600,000. Pretax pension expense reflected in the years ended December 31, 2007, 2006 and 2005, was $6.5 million, $7.0 million and $6.6 million, respectively. The Company's pension expense is currently projected to be approximately $8.0 million to $9.0 million in 2008. Funding for the Pension Plans is actuarially determined. The minimum required contributions for 2007, 2006 and 2005 were approximately $1.8 million, $2.6 million and $1.6 million, respectively. For further information on the Company's Pension Plans, see Item 8 – Note 17.

Capital expenditures
The Company's capital expenditures for 2005 through 2007 and as anticipated for 2008 through 2010 are summarized in the following table, which also includes the Company's capital needs for the retirement of maturing long-term debt.

		Actual			Estimated*	
	2005	2006	2007	2008	2009	2010
	(In millions)					
Capital expenditures:						
Electric	$27	$39	$91	$95	$186	$146
Natural gas distribution	17	15	500	65	52	44
Construction services	51	32	18	19	12	13
Pipeline and energy services	36	43	39	53	38	18
Natural gas and oil production	330	329	284	605	392	385
Construction materials and contracting	162	141	190	110	105	105
Other	15	2	2	1	1	1
Net proceeds from sale or	(41)	(31)	(25)	(7)	(2)	(2)

disposition of property**						
Net capital expenditures before discontinued operations	597	570	1,099	941	784	710
Discontinued operations	133	33	(548)	---	---	---
Net capital expenditures	730	603	551	941	784	710
Retirement of long-term debt	107	316	232	162	73	7
	$837	$919	$783	$1,103	$857	$717

* With the exception of the acquisition of approximately $235 million of natural gas and oil properties in the first quarter of 2008, the estimated 2008 through 2010 capital expenditures reflected in the above table exclude potential future acquisitions and other growth opportunities which are dependent upon the availability of economic opportunities and, as a result, capital expenditures may vary significantly from the above estimates.

** The estimated 2008 through 2010 net proceeds exclude proceeds related to the disposal of unidentified assets.

Capital expenditures for 2007, 2006 and 2005, in the preceding table include noncash transactions, including the issuance of the Company's equity securities in connection with acquisitions and the outstanding indebtedness related to the 2007 Cascade acquisition. The noncash transactions were $217.3 million in 2007, immaterial in 2006 and $46.5 million in 2005.

In 2007, the Company acquired construction materials and contracting businesses in North Dakota, Texas and Wyoming, a construction services business in Nevada, and Cascade, a natural gas distribution business. The total purchase consideration for these businesses and properties and purchase price adjustments with respect to certain other acquisitions made prior to 2007, consisting of the Company's common stock and cash, was $526.3 million.

The 2007 capital expenditures, including those for the previously mentioned acquisitions and retirements of long-term debt, were met from internal sources, the issuance of long-term debt and the Company's equity securities. Estimated capital expenditures for the years 2008 through 2010 include those for:

- System upgrades
- Routine replacements
- Service extensions
- Routine equipment maintenance and replacements
- Buildings, land and building improvements
- Pipeline and gathering projects
- Further enhancement of natural gas and oil production and reserve growth
- Power generation opportunities, including certain costs for additional electric generating capacity
- Acquisition of natural gas production assets in East Texas completed in late January 2008
- Other growth opportunities

The Company continues to evaluate potential future acquisitions and other growth opportunities; however, they are dependent upon the availability of economic opportunities and, as a result, capital expenditures may vary significantly from the estimates in the preceding table. It is anticipated that all of the funds required for capital expenditures and retirement of long-term debt for the years 2008 through 2010 will be met from various sources, including internally generated funds; the Company's credit facilities, as described below; and through the issuance of long-term debt and the Company's equity securities.

Capital resources

Certain debt instruments of the Company and its subsidiaries, including those discussed below, contain restrictive covenants, all of which the Company and its subsidiaries were in compliance with at December 31, 2007.

MDU Resources Group, Inc. The Company has a revolving credit agreement with various banks totaling $125 million (with provision for an increase, at the option of the Company on stated conditions, up to a maximum of $150 million). There were no amounts outstanding under the credit agreement at December 31, 2007. The credit agreement supports the Company's $100 million commercial paper program. Under the Company's commercial paper program, $61.0 million was outstanding at December 31, 2007. The commercial paper borrowings are classified as long-term debt as they are intended to be refinanced on a long-term basis through continued commercial paper borrowings (supported by the credit agreement, which expires in June 2011).

The Company's objective is to maintain acceptable credit ratings in order to access the capital markets through the issuance of commercial paper. Minor fluctuations in the Company's credit ratings have not limited, nor would they be expected to limit, the Company's ability to access the capital markets. In the event of a minor downgrade, the Company may experience a nominal basis point increase in overall interest rates with respect to its cost of borrowings. If the Company were to experience a significant downgrade of its credit ratings, it may need to borrow under its credit agreement.

Prior to the maturity of the credit agreement, the Company expects that it will negotiate the extension or replacement of this agreement. If the Company is unable to successfully negotiate an extension of, or replacement for, the credit agreement, or if the fees on this facility became too expensive, which the Company does not currently anticipate, the Company would seek alternative funding.

In order to borrow under the Company's credit agreement, the Company must be in compliance with the applicable covenants and certain other conditions. For information on the covenants and certain other conditions of the Company's credit agreement, see Item 8 – Note 10.

In connection with the funding of the Cascade acquisition, on June 29, 2007, the Company entered into a term loan agreement providing for a commitment amount of $310 million. The Company borrowed $310 million under this agreement on July 2, 2007. On July 11, 2007, and August 14, 2007, the Company paid down $220 million and $5 million, respectively, of the outstanding principal balance. In addition, on August 14, 2007 and August 28, 2007, the Company received $50 million and $35 million, respectively, from the repayment of an intercompany loan with MDU Energy Capital. The Company, in turn, repaid the remaining principal balance of the term loan indebtedness that it incurred to fund the acquisition of Cascade. The term loan agreement terminated on August 28, 2007.

There are no credit facilities that contain cross-default provisions between the Company and any of its subsidiaries.

The Company's issuance of first mortgage debt is subject to certain restrictions imposed under the terms and conditions of its Mortgage. Generally, those restrictions require the Company to fund $1.43 of unfunded property or use $1.00 of refunded bonds for each dollar of indebtedness incurred under the Mortgage and, in some cases, to certify to the trustee that annual earnings (pretax and before interest charges), as defined in the Mortgage, equal at least two times its annualized first mortgage bond interest costs. Under the more restrictive of the tests, as of December 31, 2007, the Company could have issued approximately $544 million of additional first mortgage bonds.

The Company's coverage of fixed charges including preferred dividends was 6.4 times for the 12 months ended December 31, 2007 and 2006. Common stockholders' equity as a percent of total capitalization was 66 percent and 63 percent at December 31, 2007 and 2006, respectively.

The Company has repurchased, and may from time to time seek to repurchase, outstanding first mortgage bonds through open market purchases or privately negotiated transactions. The Company will evaluate any such transactions in light of then existing market conditions, taking into account its liquidity and prospects for future access to capital.

As of December 31, 2007, the Company had $50.5 million of first mortgage bonds outstanding, $30.0 million of which were held by the Indenture trustee for the benefit of the senior note holders. The aggregate principal amount of the Company's outstanding first mortgage bonds, other than those held by the Indenture trustee, is $20.5 million and satisfies the lien release requirements under the Indenture. As a result, the Company may at any time, subject to satisfying certain specified conditions, require that any debt issued under its Indenture become unsecured and rank equally with all of the Company's other unsecured and unsubordinated debt (as of December 31, 2007, the only such debt outstanding under the Indenture was $30.0 million in aggregate principal amount of the Company's 5.98% Senior Notes due in 2033).

The Company has entered into a Sales Agency Financing Agreement, as amended June 25, 2007, with Wells Fargo Securities, LLC with respect to the issuance and sale of up to 3,000,000 shares of the Company's common stock, par value $1.00 per share, together with preference share purchase rights appurtenant thereto. The common stock may be offered for sale, from time to time, in accordance with the terms and conditions of the agreement, which terminates on December 1, 2008. Proceeds from the sale of shares of common stock under the agreement are expected to be used for corporate development purposes and other general corporate purposes. The offering would be made pursuant to the Company's shelf registration statement on Form S-3, as amended, which became effective on September 26, 2003, as supplemented by a prospectus supplement, dated June 28, 2007, filed with the SEC pursuant to Rule 424(b) under the Securities Act of 1933, as amended. The Company has not issued any stock under the Sales Agency Financing Agreement through December 31, 2007.

MDU Energy Capital, LLC On August 14, 2007, MDU Energy Capital entered into a $125 million master shelf agreement (dated as of August 9, 2007), and borrowed $50 million under the agreement. On August 28, 2007, MDU Energy Capital borrowed an additional $35 million under the master shelf agreement. MDU Energy Capital used the proceeds from the borrowings to repay a short-term intercompany loan from the Company applicable to the acquisition of Cascade, as previously discussed.

The master shelf agreement contains customary covenants and provisions. For information on the covenants and certain other conditions of the MDU Energy Capital master shelf agreement, see Item 8 – Note 10.

Cascade Natural Gas Corporation Cascade has a revolving credit agreement with various banks totaling $50 million with certain provisions allowing for increased borrowings, up to a maximum of $75 million. The $50 million credit agreement expires on December 28, 2012, with provisions allowing for an extension of up to two years upon consent of the banks. Cascade also has a $20 million uncommitted line of credit which may be terminated by the bank or Cascade at any time. There was $1.7 million outstanding under the Cascade credit agreements at December 31, 2007. The borrowings are classified as short-term borrowings as Cascade intends to repay the borrowings within one year. As of December 31, 2007, there were outstanding letters of credit, as discussed in Item 8 – Note 20, of which $1.9 million reduced amounts available under the $50 million credit agreement.

In order to borrow under Cascade's $50 million credit agreement, Cascade must be in compliance with the applicable covenants and certain other conditions. For information on the covenants and certain other conditions of Cascade's $50 million credit agreement, see Item 8 – Note 9.

Cascade's $50 million credit agreement contains cross-default provisions. These provisions state that if Cascade fails to make any payment with respect to any indebtedness or contingent obligation, in excess of a specified amount, under any agreement that causes such indebtedness to be due prior to its stated maturity or the contingent obligation to become payable, the agreement will be in default. Certain of Cascade's financing agreements and Cascade's practices limit the amount of subsidiary indebtedness.

Centennial Energy Holdings, Inc. Centennial has a revolving credit agreement and an uncommitted line of credit with various banks and institutions totaling $425 million with certain provisions allowing for increased borrowings. These credit agreements support Centennial's $400 million commercial paper program. There were no outstanding borrowings under the Centennial credit agreements at December 31, 2007. Under the Centennial commercial paper program there was no amount outstanding at December 31, 2007. When Centennial has commercial paper borrowings outstanding, the borrowings are classified as long-term debt as they are intended to be refinanced on a long-term basis through continued Centennial commercial paper borrowings (supported by Centennial credit agreements). The revolving credit agreement is for $400 million, which includes a provision for an increase, at the option of Centennial on stated conditions, up to a maximum of $450 million and expires on December 13, 2012. The uncommitted line of credit for $25 million may be terminated by the bank at any time. As of December 31, 2007, $56.6 million of letters of credit were outstanding, as discussed in Item 8 – Note 20, of which $44.0 million reduced amounts available under these agreements.

Centennial has an uncommitted long-term master shelf agreement that allows for borrowings of up to $550 million. Under the terms of the master shelf agreement, $418.5 million was outstanding at December 31, 2007. The ability to request additional borrowings under this master shelf agreement expires on May 8, 2009. To meet potential future financing needs, Centennial may pursue other financing arrangements, including private and/or public financing.

Centennial's objective is to maintain acceptable credit ratings in order to access the capital markets through the issuance of commercial paper. Minor fluctuations in Centennial's credit ratings have not limited, nor would they be expected to limit, Centennial's ability to access the capital markets. In the event of a minor downgrade, Centennial may experience a nominal basis point increase in overall interest rates with respect to its cost of borrowings. If Centennial were to experience a significant downgrade of its credit ratings, it may need to borrow under its committed bank lines.

Prior to the maturity of the Centennial credit agreements, Centennial expects that it will negotiate the extension or replacement of these agreements, which provide credit support to access the capital markets. In the event Centennial was unable to successfully negotiate these agreements, or in the event the fees on such facilities became too expensive, which Centennial does not currently anticipate, it would seek alternative funding.

In order to borrow under Centennial's credit agreements and the Centennial uncommitted long-term master shelf agreement, Centennial and certain of its subsidiaries must be in compliance with the applicable covenants and certain other conditions. For information on the covenants and certain other conditions of Centennial's credit agreement, see Item 8 – Note 10.

Certain of Centennial's financing agreements contain cross-default provisions. These provisions state that if Centennial or any subsidiary of Centennial fails to make any payment with respect to any indebtedness or contingent obligation, in excess of a specified amount, under any agreement that causes such indebtedness to be due prior to its stated maturity or the contingent obligation to become payable, the applicable agreements will be in default. Certain of Centennial's financing agreements and Centennial's practices limit the amount of subsidiary indebtedness.

Williston Basin Interstate Pipeline Company Williston Basin has an uncommitted long-term master shelf agreement that allows for borrowings up to $100 million. Under the terms of the master shelf agreement, $80.0 million was outstanding at December 31, 2007. The ability to request additional borrowings under this master shelf agreement expires on December 20, 2008.

In order to borrow under its uncommitted long-term master shelf agreement, Williston Basin must be in compliance with the applicable covenants and certain other conditions. For information on the covenants and certain other conditions of the uncommitted long-term master shelf agreement, see Item 8 – Note 10.

Off balance sheet arrangements
In connection with the sale of MPX in June 2005 to Petrobras, an indirect wholly owned subsidiary of the Company has agreed to indemnify Petrobras for 49 percent of any losses that Petrobras may incur from certain contingent liabilities specified in the purchase agreement. For more information, see Item 8 – Note 20.

Centennial continues to guarantee CEM’s obligations under a construction contract for a 550-MW combined-cycle electric generating facility near Hobbs, New Mexico. For more information, see Item 8 – Note 20.

Contractual obligations and commercial commitments

For more information on the Company's contractual obligations on long-term debt, operating leases, purchase commitments and uncertain tax positions, see Item 8 – Notes 10, 15 and 20. At December 31, 2007, the Company's commitments under these obligations were as follows:

	2008	2009	2010	2011	2012	Thereafter	Total
				(In millions)			
Long-term debt	$ 161.7	$ 73.4	$ 7.3	$ 128.0	$ 135.5	$ 802.6	$ 1,308.5
Estimated interest payments*	70.8	63.5	61.7	56.4	51.3	335.5	639.2
Operating leases	20.3	16.0	13.7	10.3	8.4	48.8	117.5
Purchase commitments	479.2	340.0	233.4	163.7	105.6	323.1	1,645.0
	$ 732.0	$ 492.9	$ 316.1	$ 358.4	$ 300.8	$ 1,510.0	$ 3,710.2

* Estimated interest payments are calculated based on the applicable rates and payment dates.

Not reflected in the table above are $3.7 million in uncertain tax positions for which the year of settlement is not reasonably possible to determine.

EFFECTS OF INFLATION

Inflation did not have a significant effect on the Company's operations in 2007, 2006 or 2005.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

The Company is exposed to the impact of market fluctuations associated with commodity prices, interest rates and foreign currency. The Company has policies and procedures to assist in controlling these market risks and utilizes derivatives to manage a portion of its risk.

For more information on derivatives and the Company's derivative policies and procedures, see Item 8 – Notes 1 and 7.

Commodity price risk

Fidelity utilizes derivative instruments to manage a portion of the market risk associated with fluctuations in the price of natural gas and oil on its forecasted sales of natural gas and oil production. Cascade utilizes derivative instruments to manage a portion of the market risk associated with fluctuations in the price of natural gas on its forecasted purchases of natural gas.

The following table summarizes hedge agreements entered into by Fidelity and Cascade as of December 31, 2007. These agreements call for Fidelity to receive fixed prices and pay variable prices, and for Cascade to receive variable prices and pay fixed prices.

	(Forward notional volume and fair value in thousands)		
Fidelity	Weighted Average Fixed Price	Forward Notional Volume (MMBtu)	Fair Value

	(Per MMBtu)			
Natural gas swap agreements maturing in 2008	$ 7.90	10,978	$	8,035
Cascade core				
Natural gas swap agreements maturing in 2008	$ 7.71	20,443	$	(11,542)
Natural gas swap agreements maturing in 2009	$ 7.79	13,410	$	(195)
Natural gas swap agreements maturing in 2010	$ 7.72	5,902	$	1,044
Cascade non-core				
Natural gas swap agreements maturing in 2008	$ 7.35	1,391	$	(1,014)

Fidelity	Weighted Average Floor/Ceiling Price (Per MMBtu/Bbl)	Forward Notional Volume (MMBtu/Bbl)	Fair Value
Natural gas collar agreements maturing in 2008	$ 7.25/$8.46	11,895	$ 3,574
Oil collar agreement maturing in 2008	$ 67.50/$78.70	73	$ (1,112)

The following table summarizes hedge agreements entered into by Fidelity as of December 31, 2006. These agreements call for Fidelity to receive fixed prices and pay variable prices.

(Forward notional volume and fair value in thousands)

Fidelity	Weighted Average Fixed Price (Per MMBtu)	Forward Notional Volume (MMBtu)	Fair Value
Natural gas swap agreements maturing in 2007	$ 7.69	9,125	$ 14,845

Fidelity	Weighted Average Floor/Ceiling Price (Per MMBtu)	Forward Notional Volume (MMBtu)	Fair Value
Natural gas collar agreements maturing in 2007	$ 7.87/$10.74	10,123	$ 17,256

Interest rate risk

The Company uses fixed and variable rate long-term debt to partially finance capital expenditures and mandatory debt retirements. These debt agreements expose the Company to market risk related to changes in interest rates. The Company manages this risk by taking advantage of market conditions when timing the placement of long-term or permanent financing. The Company also has historically used interest rate swap agreements to manage a portion of the Company's interest rate risk and may take advantage of such agreements in the future to minimize such risk. At December 31, 2007 and 2006, the Company had no outstanding interest rate hedges.

The following table shows the amount of debt, including current portion, and related weighted average interest rates, both by expected maturity dates, as of December 31, 2007.

	2008	2009	2010	2011	2012	Thereafter	Total	Fair Value
				(Dollars in millions)				
Long-term debt:								
Fixed rate	$ 161.7	$ 73.4	$ 7.3	$ 67.0	$ 135.5	$ 802.6	$ 1,247.5	$ 1,233.3
Weighted average interest rate	4.5%	6.1%	6.8%	7.1%	5.9%	5.9%	5.8%	---
Variable rate	---	---	---	$ 61.0	---	---	$ 61.0	$ 60.6
Weighted average interest rate	---	---	---	4.9%	---	---	4.9%	---

Foreign currency risk

MDU Brasil's equity method investments in the Brazilian Transmission Lines are exposed to market risks from changes in foreign currency exchange rates between the U.S. dollar and the Brazilian Real. For further information, see Item 8 – Note 4. At December 31, 2007 and 2006, the Company had no outstanding foreign currency hedges.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

The management of MDU Resources Group, Inc. is responsible for establishing and maintaining adequate internal control over financial reporting as defined in Rules 13a-15(f) under the Securities Exchange Act of 1934. The Company's internal control system is designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles.

All internal control systems, no matter how well designed, have inherent limitations. Therefore, even those systems determined to be effective can provide only reasonable assurance with respect to financial statement preparation and presentation. Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

Management assessed the effectiveness of the Company's internal control over financial reporting as of December 31, 2007. In making this assessment, management used the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) in Internal Control–Integrated Framework.

Based on our evaluation under the framework in Internal Control–Integrated Framework, management concluded that the Company's internal control over financial reporting was effective as of December 31, 2007.

The effectiveness of the Company's internal control over financial reporting as of December 31, 2007, has been audited by Deloitte & Touche LLP, an independent registered public accounting firm, as stated in their report.

/s/ Terry D. Hildestad	/s/ Vernon A. Raile
Terry D. Hildestad	Vernon A. Raile
President and Chief Executive Officer	Executive Vice President, Treasurer and Chief Financial Officer

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

TO THE BOARD OF DIRECTORS AND STOCKHOLDERS OF MDU RESOURCES GROUP, INC.:

We have audited the accompanying consolidated balance sheets of MDU Resources Group, Inc. and subsidiaries (the “Company”) as of December 31, 2007 and 2006, and the related consolidated statements of income, common stockholders' equity, and cash flows for each of the three years in the period ended December 31, 2007. Our audits also included the financial statement schedule for each of the three years in the period ended December 31, 2007, listed in the Index at Item 15. These consolidated financial statements and the financial statement schedule are the responsibility of the Company's management. Our responsibility is to express an opinion on these consolidated financial statements and financial statement schedule based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the consolidated financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the consolidated financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall consolidated financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of MDU Resources Group, Inc. and subsidiaries as of December 31, 2007 and 2006, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2007, in conformity with accounting principles generally accepted in the United States of America. Also, in our opinion, the financial statement schedule, when considered in relation to the basic consolidated financial statements taken as a whole, presents fairly, in all material respects, the information set forth therein.

As discussed in Note 17 to the consolidated financial statements, the Company adopted SFAS No. 158 Employers’ Accounting for Defined Benefit Pension and Other Postretirement Plans effective as of December 31, 2006.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the Company's internal control over financial reporting as of December 31, 2007, based on the criteria established in Internal Control–Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 12, 2008, expressed an unqualified opinion on the Company's internal control over financial reporting.

/s/ Deloitte & Touche LLP

Minneapolis, Minnesota
February 12, 2008

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

TO THE BOARD OF DIRECTORS AND STOCKHOLDERS OF MDU RESOURCES GROUP, INC.:

We have audited the internal control over financial reporting of MDU Resources Group, Inc. and subsidiaries (the "Company") as of December 31, 2007, based on criteria established in Internal Control–Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission. The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Report on Internal Control Over Financial Reporting. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

A company's internal control over financial reporting is a process designed by, or under the supervision of, the company's principal executive and principal financial officers, or persons performing similar functions, and effected by the company's board of directors, management, and other personnel to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of the inherent limitations of internal control over financial reporting, including the possibility of collusion or improper management override of controls, material misstatements due to error or fraud may not be prevented or detected on a timely basis. Also, projections of any evaluation of the effectiveness of the internal control over financial reporting to future periods are subject to the risk that the controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2007, based on the criteria established in Internal Control–Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated financial statements and financial statement schedule as of and for the year ended December 31, 2007 of the Company and our report dated February 12, 2008 expressed an unqualified opinion on those consolidated financial statements and financial statement schedule and included an explanatory paragraph regarding the Company's adoption of SFAS No. 158 Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans effective as of December 31, 2006.

/s/ Deloitte & Touche LLP

Minneapolis, Minnesota
February 12, 2008

MDU RESOURCES GROUP, INC.
CONSOLIDATED STATEMENTS OF INCOME

Years ended December 31,	2007	2006	2005
	(In thousands, except per share amounts)		
Operating revenues:			
Electric, natural gas distribution and pipeline and energy services	$ 1,095,709	$ 889,286	$ 950,324
Construction services, natural gas and oil production, construction materials and contracting, and other	3,152,187	3,115,253	2,453,599
	4,247,896	4,004,539	3,403,923
Operating expenses:			
Fuel and purchased power	69,616	67,414	63,591
Purchased natural gas sold	377,404	268,981	329,190
Operation and maintenance:			
Electric, natural gas distribution and pipeline and energy services	215,587	183,992	155,323
Construction services, natural gas and oil production, construction materials and contracting, and other	2,572,864	2,577,755	2,080,451
Depreciation, depletion and amortization	301,932	256,531	219,440
Taxes, other than income	153,373	126,791	117,405
	3,690,776	3,481,464	2,965,400
Operating income	557,120	523,075	438,523
Earnings from equity method investments	19,609	10,838	20,192
Other income	8,318	12,071	7,209
Interest expense	72,237	72,095	54,384
Income before income taxes	512,810	473,889	411,540
Income taxes	190,024	166,111	146,249
Income from continuing operations	322,786	307,778	265,291
Income from discontinued operations, net of tax (Note 3)	109,334	7,979	9,792
Net income	432,120	315,757	275,083
Dividends on preferred stocks	685	685	685
Earnings on common stock	$ 431,435	$ 315,072	$ 274,398
Earnings per common share – basic:			
Earnings before discontinued operations	$ 1.77	$ 1.70	$ 1.48
Discontinued operations, net of tax	.60	.05	.06
Earnings per common share – basic	$ 2.37	$ 1.75	$ 1.54
Earnings per common share – diluted:			
Earnings before discontinued operations	$ 1.76	$ 1.69	$ 1.47
Discontinued operations, net of tax	.60	.05	.06
Earnings per common share – diluted	$ 2.36	$ 1.74	$ 1.53
Dividends per common share	$ .5600	$ .5234	$ .4934
Weighted average common shares outstanding – basic	181,946	180,234	178,365
Weighted average common shares outstanding – diluted	182,902	181,392	179,490

The accompanying notes are an integral part of these consolidated financial statements.

MDU RESOURCES GROUP, INC.
CONSOLIDATED BALANCE SHEETS

December 31,	2007	2006

(In thousands, except shares and per share amounts)

ASSETS		
Current assets:		
Cash and cash equivalents	$ 105,820	$ 73,078
Receivables, net	715,484	622,478
Inventories	229,255	204,440
Deferred income taxes	7,046	---
Short-term investments	91,550	23,250
Prepayments and other current assets	64,998	57,833
Current assets held for sale (Note 3)	179	12,656
	1,214,332	993,735
Investments	118,602	155,111
Property, plant and equipment (Note 1)	5,930,246	4,727,725
Less accumulated depreciation, depletion and amortization	2,270,691	1,735,302
	3,659,555	2,992,423
Deferred charges and other assets:		
Goodwill (Note 5)	425,698	224,298
Other intangible assets, net (Note 5)	27,792	22,802
Other	146,455	103,840
Noncurrent assets held for sale (Note 3)	---	411,265
	599,945	762,205
	$ 5,592,434	$ 4,903,474
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities:		
Short-term borrowings (Note 9)	$ 1,700	$ ---
Long-term debt due within one year	161,682	84,034
Accounts payable	369,235	289,836
Taxes payable	60,407	54,290
Deferred income taxes	---	5,969
Dividends payable	26,619	24,606
Accrued compensation	66,255	62,121
Other accrued liabilities	163,990	118,206
Current liabilities held for sale (Note 3)	---	14,900
	849,888	653,962
Long-term debt (Note 10)	1,146,781	1,170,548
Deferred credits and other liabilities:		
Deferred income taxes	668,016	546,602
Other liabilities	396,430	336,916
Noncurrent liabilities held for sale (Note 3)	---	30,533
	1,064,446	914,051
Commitments and contingencies (Notes 17, 19 and 20)		
Stockholders' equity:		
Preferred stocks (Note 12)	15,000	15,000
Common stockholders' equity:		
Common stock (Note 13)		
Authorized – 500,000,000 shares, $1.00 par value in 2007, 250,000,000 shares, $1.00 par value in 2006		
Issued – 182,946,528 shares in 2007 and 181,557,543 shares in 2006	182,947	181,558
Other paid-in capital	912,806	874,253
Retained earnings	1,433,585	1,104,210
Accumulated other comprehensive loss	(9,393)	(6,482)

Treasury stock at cost – 538,921 shares	(3,626)	(3,626)
Total common stockholders' equity	2,516,319	2,149,913
Total stockholders' equity	2,531,319	2,164,913
	$ 5,592,434	$ 4,903,474

The accompanying notes are an integral part of these consolidated financial statements.

MDU RESOURCES GROUP, INC.
CONSOLIDATED STATEMENTS OF COMMON STOCKHOLDERS' EQUITY

Years ended December 31, 2007, 2006 and 2005

	Common Stock		Other Paid-in	Retained	Accumulated Other Comprehensive	Treasury Stock		
	Shares	Amount	Capital	Earnings	Loss	Shares	Amount	Total
				(In thousands, except shares)				
Balance at December 31, 2004	118,586,065	$ 118,586	$ 863,449	$ 699,095	$ (11,491)	(359,281)	$ (3,626)	$ 1,666,013
Comprehensive income:								
Net income	---	---	---	275,083	---	---	---	275,083
Other comprehensive income (loss), net of tax -								
Net unrealized loss on derivative instruments qualifying as hedges	---	---	---	---	(21,800)	---	---	(21,800)
Pension liability adjustment	---	---	---	---	574	---	---	574
Foreign currency translation adjustment	---	---	---	---	(1,099)	---	---	(1,099)
Total comprehensive income	---	---	---	---	---	---	---	252,758
Dividends on preferred stocks	---	---	---	(685)	---	---	---	(685)
Dividends on common stock	---	---	---	(88,698)	---	---	---	(88,698)
Tax benefit on stock-based compensation	---	---	5,487	---	---	---	---	5,487
Issuance of common stock	1,676,721	1,677	40,070	---	---	---	---	41,747
	120,262,786	120,263	909,006	884,795	(33,816)	(359,281)	(3,626)	1,876,622

Balance at December 31, 2005								
Comprehensive income:								
Net income	---	---	---	315,757	---	---	---	315,757
Other comprehensive income (loss), net of tax -								
Net unrealized gain on derivative instruments qualifying as hedges	---	---	---	---	45,610	---	---	45,610
Pension liability adjustment	---	---	---	---	1,761	---	---	1,761
Foreign currency translation adjustment	---	---	---	---	(1,585)	---	---	(1,585)
Total comprehensive income	---	---	---	---	---	---	---	361,543
SFAS No. 158 transition adjustment	---	---	---	---	(18,452)	---	---	(18,452)
Dividends on preferred stocks	---	---	---	(685)	---	---	---	(685)
Dividends on common stock	---	---	---	(95,657)	---	---	---	(95,657)
Tax benefit on stock-based compensation	---	---	2,524	---	---	---	---	2,524
Issuance of common stock (pre-split)	120,702	121	3,242	---	---	---	---	3,363
Three-for-two common stock split (Note 13)	60,191,744	60,192	(60,192)	---	---	(179,640)	---	---
Issuance of common stock (post-split)	982,311	982	19,673	---	---	---	---	20,655
Balance at December 31, 2006	181,557,543	181,558	874,253	1,104,210	(6,482)	(538,921)	(3,626)	2,149,913
Comprehensive income:								
Net income	---	---	---	432,120	---	---	---	432,120

Other comprehensive income (loss), net of tax -								
Net unrealized loss on derivative instruments qualifying as hedges	---	---	---	---	(13,505)	---	---	(13,505)
Pension liability adjustment	---	---	---	---	3,012	---	---	3,012
Foreign currency translation adjustment	---	---	---	---	7,177	---	---	7,177
Net unrealized gain on available-for-sale investments	---	---	---	---	405	---	---	405
Total comprehensive income	---	---	---	---	---	---	---	429,209
FIN 48 transition adjustment	---	---	---	31	---	---	---	31
Dividends on preferred stocks	---	---	---	(685)	---	---	---	(685)
Dividends on common stock	---	---	---	(102,091)	---	---	---	(102,091)
Tax benefit on stock-based compensation	---	---	5,398	---	---	---	---	5,398
Issuance of common stock	1,388,985	1,389	33,155	---	---	---	---	34,544
Balance at December 31, 2007	182,946,528	$ 182,947	$ 912,806	$ 1,433,585	$ (9,393)	(538,921)	$ (3,626)	$ 2,516,319

The accompanying notes are an integral part of these consolidated financial statements.

MDU RESOURCES GROUP, INC.

CONSOLIDATED STATEMENTS OF CASH FLOWS

Years ended December 31,	2007	2006	2005
		(In thousands)	
Operating activities:			
Net income	$ 432,120	$ 315,757	$ 275,083
Income from discontinued operations, net of tax	109,334	7,979	9,792
Income from continuing operations	322,786	307,778	265,291
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation, depletion and amortization	301,932	256,531	219,440

Earnings, net of distributions, from equity method investments	(14,031)	(4,093)	(14,385)
Deferred income taxes	67,272	38,645	23,157
Changes in current assets and liabilities, net of acquisitions:			
Receivables	(40,256)	(7,639)	(119,168)
Inventories	(7,130)	(29,736)	(20,217)
Other current assets	(7,356)	(9,597)	435
Accounts payable	24,702	19,834	52,121
Other current liabilities	(22,932)	33,394	26,676
Other noncurrent changes	9,594	20,913	21,379
Net cash provided by continuing operations	634,581	626,030	454,729
Net cash provided by (used in) discontinued operations	(71,389)	33,539	28,821
Net cash provided by operating activities	563,192	659,569	483,550
Investing activities:			
Capital expenditures	(558,283)	(479,872)	(377,856)
Acquisitions, net of cash acquired	(348,490)	(113,781)	(213,557)
Net proceeds from sale or disposition of property	24,983	30,501	40,460
Investments	(67,140)	(59,202)	1,833
Proceeds from sale of equity method investments	58,450	---	38,166
Net cash used in continuing operations	(890,480)	(622,354)	(510,954)
Net cash provided by (used in) discontinued operations	548,216	(37,872)	(132,956)
Net cash used in investing activities	(342,264)	(660,226)	(643,910)
Financing activities:			
Issuance of short-term borrowings	311,700	---	---
Repayment of short-term borrowings	(310,000)	---	---
Issuance of long-term debt	120,250	356,352	353,937
Repayment of long-term debt	(232,464)	(315,486)	(106,822)
Proceeds from issuance of common stock	17,263	19,963	9,165
Dividends paid	(100,641)	(93,450)	(87,551)
Tax benefit on stock-based compensation	5,398	2,524	---
Net cash provided by (used in) continuing operations	(188,494)	(30,097)	168,729
Net cash provided by discontinued operations	---	---	---
Net cash provided by (used in) financing activities	(188,494)	(30,097)	168,729
Effect of exchange rate changes on cash and cash equivalents	308	(1,666)	---
Increase (decrease) in cash and cash equivalents	32,742	(32,420)	8,369
Cash and cash equivalents – beginning of year	73,078	105,498	97,129
Cash and cash equivalents – end of year	$ 105,820	$ 73,078	$ 105,498

The accompanying notes are an integral part of these consolidated financial statements.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

NOTE 1 – SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Basis of presentation

The consolidated financial statements of the Company include the accounts of the following businesses: electric, natural gas distribution, construction services, pipeline and energy services, natural gas and oil production, construction materials and contracting, and other. The electric, natural gas distribution, and pipeline and energy services businesses are substantially all regulated. Construction services, natural gas and oil production, construction materials and contracting, and other are nonregulated. For further descriptions of the Company's businesses, see Note 16. The statements also include the ownership interests in the assets, liabilities and expenses of two jointly owned electric generating facilities.

The Company's regulated businesses are subject to various state and federal agency regulations. The accounting policies followed by these businesses are generally subject to the Uniform System of Accounts of the FERC. These accounting policies differ in some respects from those used by the Company's nonregulated businesses.

The Company's regulated businesses account for certain income and expense items under the provisions of SFAS No. 71. SFAS No. 71 requires these businesses to defer as regulatory assets or liabilities certain items that would have otherwise been reflected as expense or income, respectively, based on the expected regulatory treatment in future rates. The expected recovery or flowback of these deferred items generally is based on specific ratemaking decisions or precedent for each item. Regulatory assets and liabilities are being amortized consistently with the regulatory treatment established by the FERC and the applicable state public service commissions. See Note 6 for more information regarding the nature and amounts of these regulatory deferrals.

Cash and cash equivalents

The Company considers all highly liquid investments purchased with an original maturity of three months or less to be cash equivalents.

Allowance for doubtful accounts

The Company's allowance for doubtful accounts as of December 31, 2007 and 2006, was $14.6 million and $7.7 million, respectively.

Natural gas in underground storage

Natural gas in underground storage for the Company's regulated operations is generally carried at cost using the last-in, first-out method. The portion of the cost of natural gas in underground storage expected to be used within one year was included in inventories and was $28.8 million and $32.6 million at December 31, 2007 and 2006, respectively. The remainder of natural gas in underground storage, which represents the cost of the gas required to maintain pressure levels for normal operating purposes, was included in other assets and was $43.0 million and $44.2 million at December 31, 2007 and 2006, respectively.

Inventories

Inventories, other than natural gas in underground storage for the Company's regulated operations, consisted primarily of aggregates held for resale of $102.2 million and $88.1 million, materials and supplies of $56.0 million and $54.1 million, and other inventories of $42.3 million and $29.6 million, as of December 31, 2007 and 2006, respectively. These inventories were stated at the lower of average cost or market value.

Short-term investments

The Company had auction rate securities of $91.6 million and $23.3 million at December 31, 2007 and 2006, respectively, which are long-term variable rate bonds tied to short-term interest rates that are reset through an auction process which typically occurs every 90 days or less. The Company accounts for these investments as available-for-sale in accordance with SFAS No. 115. Due to the short interest rate reset period, the fair value of the auction rate securities approximates cost and, as a result, there are no accumulated unrealized gains or losses recorded in accumulated other comprehensive income on the Consolidated Balance Sheets related to these investments.

Investments

The Company's investments include its equity method investments as discussed in Note 4, the cash surrender value of life insurance policies, and investments in fixed-income and equity securities which are accounted for as available-for-sale investments in accordance with SFAS No. 115. Under the equity method, investments are initially recorded at cost and adjusted for dividends and undistributed earnings and losses. The Company's fixed-income and equity securities are recorded at fair value with any unrealized gains and losses, net of income taxes, recorded in accumulated other comprehensive income (loss) on the Consolidated Balance Sheets until realized. For more information, see comprehensive income in this note.

Property, plant and equipment

Additions to property, plant and equipment are recorded at cost. When regulated assets are retired, or otherwise disposed of in the ordinary course of business, the original cost of the asset is charged to accumulated depreciation. With respect to the retirement or disposal of all other assets, except for natural gas and oil production properties as described in natural gas and oil properties in this note, the resulting gains or losses are recognized as a component of income. The Company is permitted to capitalize AFUDC on regulated construction projects and to include such amounts in rate base when the related facilities are placed in service. In addition, the Company capitalizes interest, when applicable, on certain construction projects associated with its other operations. The amount of AFUDC and interest capitalized was $7.1 million, $5.8 million and $4.3 million in 2007, 2006 and 2005, respectively. Generally, property, plant and equipment are depreciated on a straight-line basis over the average useful lives of the assets, except for depletable aggregate reserves, which are depleted based on the units-of-production method based on recoverable aggregate reserves, and natural gas and oil production properties, which are amortized on the units-of-production method based on total reserves.

Property, plant and equipment at December 31 was as follows:

	2007	2006	Estimated Depreciable Life in Years
	(Dollars in thousands, as applicable)		
Regulated:			
Electric:			
Electric generation, distribution and transmission plant	$ 784,705	$ 703,838	4-50
Natural gas distribution:			
Natural gas distribution plant	948,446	289,106	4-45
Pipeline and energy services:			
Natural gas transmission, gathering and storage facilities	403,459	384,354	8-104
Nonregulated:			
Construction services:			
Land	4,513	3,974	-
Buildings and improvements	11,987	11,288	3-40
Machinery, vehicles and equipment	76,937	70,687	2-10
Other	8,498	8,805	3-10
Pipeline and energy services:			
Natural gas gathering and other facilities	197,253	178,242	3-20
Natural gas and oil production:			
Natural gas and oil properties	1,892,757	1,606,508	*
Other	31,142	29,737	3-15

Construction materials and contracting:			
Land	115,935	95,294	-
Buildings and improvements	94,598	96,533	1-40
Machinery, vehicles and equipment	921,199	817,209	1-20
Construction in progress	22,253	23,968	-
Aggregate reserves	384,731	377,653	**
Other:			
Land	3,022	3,079	-
Other	28,811	27,450	3-40
Less accumulated depreciation, depletion and amortization	2,270,691	1,735,302	
Net property, plant and equipment	$ 3,659,555	$ 2,992,423	

* Amortized on the units-of-production method based on total proved reserves at an Mcf equivalent average rate of $1.59, $1.38 and $1.19 for the years ended December 31, 2007, 2006 and 2005, respectively. Includes natural gas and oil production properties accounted for under the full-cost method, of which $142.5 million and $164.0 million were excluded from amortization at December 31, 2007 and 2006, respectively.

** Depleted on the units-of-production method based on recoverable aggregate reserves.

Impairment of long-lived assets

The Company reviews the carrying values of its long-lived assets, excluding goodwill and natural gas and oil properties, whenever events or changes in circumstances indicate that such carrying values may not be recoverable. The determination of whether an impairment has occurred is based on an estimate of undiscounted future cash flows attributable to the assets, compared to the carrying value of the assets. If impairment has occurred, the amount of the impairment recognized is determined by estimating the fair value of the assets and recording a loss if the carrying value is greater than the fair value. No significant impairment losses were recorded in 2007, 2006 and 2005. Unforeseen events and changes in circumstances could require the recognition of other impairment losses at some future date.

Goodwill

Goodwill represents the excess of the purchase price over the fair value of identifiable net tangible and intangible assets acquired in a business combination. Goodwill is required to be tested for impairment annually, which is completed in the fourth quarter, or more frequently if events or changes in circumstances indicate that goodwill may be impaired. For more information on goodwill impairments and goodwill, see Notes 3 and 5.

Natural gas and oil properties

The Company uses the full-cost method of accounting for its natural gas and oil production activities. Under this method, all costs incurred in the acquisition, exploration and development of natural gas and oil properties are capitalized and amortized on the units-of-production method based on total proved reserves. Any conveyances of properties, including gains or losses on abandonments of properties, are treated as adjustments to the cost of the properties with no gain or loss recognized. Capitalized costs are subject to a "ceiling test" that limits such costs to the aggregate of the present value of future net revenues of proved reserves based on single point-in-time spot market prices, as mandated under the rules of the SEC, plus the cost of unproved properties. Future net revenue is estimated based on end-of-quarter spot market prices adjusted for contracted price changes. If capitalized costs exceed the full-cost ceiling at the end of any quarter, a permanent noncash write-down is required to be charged to earnings in that quarter unless subsequent price changes eliminate or reduce an indicated write-down.

At December 31, 2007 and 2006, the Company's full-cost ceiling exceeded the Company's capitalized cost. However, sustained downward movements in natural gas and oil prices subsequent to December 31, 2007, could result in a future write-down of the Company's natural gas and oil properties.

The following table summarizes the Company's natural gas and oil properties not subject to amortization at December 31, 2007, in total and by the year in which such costs were incurred:

		Year Costs Incurred			
	Total	2007	2006	2005	2004 and prior
			(In thousands)		
Acquisition	$ 62,619	$ 15,632	$ 19,135	$ 8,812	$ 19,040
Development	60,352	33,380	16,853	5,225	4,894
Exploration	15,643	13,771	812	1,060	---
Capitalized interest	3,910	1,771	1,038	426	675
Total costs not subject to amortization	$ 142,524	$ 64,554	$ 37,838	$ 15,523	$ 24,609

Costs not subject to amortization as of December 31, 2007, consisted primarily of unevaluated leaseholds, drilling costs, seismic costs and capitalized interest associated primarily with CBNG in the Powder River Basin of Montana and Wyoming; oil and gas development in the Big Horn Basin of Wyoming; an enhanced recovery development project in the Cedar Creek Anticline in southeastern Montana; oil and gas development in the Paradox Basin of Utah; a waterflood facility and injection project in southern Texas; and development of the Bakken play in western North Dakota. The Company expects that the majority of these costs will be evaluated within the next five years and included in the amortization base as the properties are evaluated and/or developed.

Revenue recognition

Revenue is recognized when the earnings process is complete, as evidenced by an agreement between the customer and the Company, when delivery has occurred or services have been rendered, when the fee is fixed or determinable and when collection is reasonably assured. The Company recognizes utility revenue each month based on the services provided to all utility customers during the month. Accrued unbilled revenue which is included in receivables, net, represents revenues recognized in excess of amounts billed. Accrued unbilled revenue at Montana-Dakota and Cascade was $66.6 million at December 31, 2007. Accrued unbilled revenue at Montana-Dakota was $35.6 million at December 31, 2006. The Company recognizes construction contract revenue at its construction businesses using the percentage-of-completion method as discussed later. The Company recognizes revenue from natural gas and oil production properties only on that portion of production sold and allocable to the Company's ownership interest in the related well. The Company recognizes all other revenues when services are rendered or goods are delivered.

Percentage-of-completion method

The Company recognizes construction contract revenue from fixed-price and modified fixed-price construction contracts at its construction businesses using the percentage-of-completion method, measured by the percentage of costs incurred to date to estimated total costs for each contract. If a loss is anticipated on a contract, the loss is immediately recognized. Costs in excess of billings on uncompleted contracts of $45.2 million and $41.3 million at December 31, 2007 and 2006, respectively, represent revenues recognized in excess of amounts billed and were included in receivables, net. Billings in excess of costs on uncompleted contracts of $81.4 million and $84.2 million at December 31, 2007 and 2006, respectively, represent billings in excess of revenues recognized and were included in accounts payable. Amounts representing balances billed but not paid by customers under retainage provisions in contracts amounted to $80.3 million and $81.8 million at December 31, 2007 and 2006, respectively. The amounts expected to be paid within one year or less are included in receivables, net, and amounted to $68.9 million and $81.8 million at December 31, 2007 and 2006, respectively. The long-term retainage which was included in deferred charges and other assets – other was $11.4 million at December 31, 2007.

Derivative instruments

The Company's policy allows the use of derivative instruments as part of an overall energy price, foreign currency and interest rate risk management program to efficiently manage and minimize commodity price, foreign currency and interest rate risk. The Company's policy prohibits the use of derivative instruments for speculating to take advantage of market trends and conditions, and the Company has procedures in place to monitor compliance with its policies. The Company is exposed to credit-related losses in relation to derivative instruments in the event of nonperformance by counterparties. The Company's policy generally requires that natural gas and oil price derivative instruments at Fidelity and interest rate derivative instruments not exceed a period of 24 months and foreign currency derivative instruments not exceed a 12-month period. The Company's policy allows Cascade to maintain a portfolio of natural gas derivative instruments not to exceed a period of three years. The Company's policy requires settlement of natural gas and oil price derivative instruments monthly and all interest rate derivative transactions must be settled over a period that will not exceed 90 days, and any foreign currency derivative transaction settlement periods may not exceed a 12-month period. The Company has policies and procedures that management believes minimize credit-risk exposure. Accordingly, the Company does not anticipate any material effect on its financial position or results of operations as a result of nonperformance by counterparties. For more information on derivative instruments, see Note 7.

Asset retirement obligations

The Company records the fair value of a liability for an asset retirement obligation in the period in which it is incurred. When the liability is initially recorded, the Company capitalizes a cost by increasing the carrying amount of the related long-lived asset. Over time, the liability is accreted to its present value each period, and the capitalized cost is depreciated over the useful life of the related asset. Upon settlement of the liability, the Company either settles the obligation for the recorded amount or incurs a gain or loss at its nonregulated operations or incurs a regulatory asset or liability at its regulated operations. For more information on asset retirement obligations, see Note 11.

Natural gas costs recoverable or refundable through rate adjustments

Under the terms of certain orders of the applicable state public service commissions, the Company is deferring natural gas commodity, transportation and storage costs that are greater or less than amounts presently being recovered through its existing rate schedules. Such orders generally provide that these amounts are recoverable or refundable through rate adjustments within a period ranging from 14 to 28 months from the time such costs are paid. Natural gas costs refundable through rate adjustments were $11.6 million and $7.5 million at December 31, 2007 and 2006, respectively, which is included in other accrued liabilities. Natural gas costs recoverable through rate adjustments were $3.9 million at December 31, 2007, which is included in prepayments and other current assets.

Insurance

Certain subsidiaries of the Company are insured for workers' compensation losses, subject to deductibles ranging up to $750,000 per occurrence. Automobile liability and general liability losses are insured, subject to deductibles ranging up to $500,000 per accident or occurrence. These subsidiaries have excess coverage above the primary automobile and general liability policies on a claims first-made basis beyond the deductible levels. The subsidiaries of the Company are retaining losses up to the deductible amounts accrued on the basis of estimates of liability for claims incurred and for claims incurred but not reported.

Income taxes

The Company provides deferred federal and state income taxes on all temporary differences between the book and tax basis of the Company's assets and liabilities. Excess deferred income tax balances associated with the Company's rate-regulated activities resulting from the Company's adoption of SFAS No. 109 have been recorded as a regulatory liability and are included in other liabilities. These regulatory liabilities are expected to be reflected as a reduction in future rates charged to customers in accordance with applicable regulatory procedures.

The Company uses the deferral method of accounting for investment tax credits and amortizes the credits on electric and natural gas distribution plant over various periods that conform to the ratemaking treatment prescribed by the applicable state public service commissions.

Foreign currency translation adjustment

The functional currency of the Company's investment in the Brazilian Transmission Lines and its former investment in the Termoceara Generating Facility, as further discussed in Note 4, is the Brazilian Real. Translation from the Brazilian Real to the U.S. dollar for assets and liabilities is performed using the exchange rate in effect at the balance sheet date. Revenues and expenses are translated on a year-to-date basis using weighted average daily exchange rates. Adjustments resulting from such translations are reported as a separate component of other comprehensive income (loss) in common stockholders' equity.

Transaction gains and losses resulting from the effect of exchange rate changes on transactions denominated in a currency other than the functional currency of the reporting entity would be recorded in income.

Common stock split

On May 11, 2006, the Company's Board of Directors approved a three-for-two common stock split. For more information on the common stock split, see Note 13.

Earnings per common share

Basic earnings per common share were computed by dividing earnings on common stock by the weighted average number of shares of common stock outstanding during the year. Diluted earnings per common share were computed by dividing earnings on common stock by the total of the weighted average number of shares of common stock outstanding during the year, plus the effect of outstanding stock options, restricted stock grants and performance share awards. In 2007, 2006 and 2005, there were no shares excluded from the calculation of diluted earnings per share. Common stock outstanding includes issued shares less shares held in treasury.

Stock-based compensation

On January 1, 2006, the Company adopted SFAS No. 123 (revised). This accounting standard revises SFAS No. 123 and requires entities to recognize compensation expense in an amount equal to the grant-date fair value of share-based payments granted to employees. SFAS No. 123 (revised) was adopted using the modified prospective method, recognizing compensation expense for all awards granted after the date of adoption of the standard and for the unvested portion of previously granted awards that remain outstanding at the date of adoption. In accordance with the modified prospective method, the Company's consolidated financial statements for prior periods have not been restated to reflect, and do not include, the impact of SFAS No. 123 (revised).

On January 1, 2003, the Company adopted the fair value recognition provisions of SFAS No. 123 and began expensing the fair market value of stock options for all awards granted on or after January 1, 2003. As permitted by SFAS No. 148, the Company accounted for stock options granted prior to January 1, 2003, under APB Opinion No. 25 and no compensation expense was recognized as the options granted had an exercise price equal to the market value of the underlying common stock on the date of the grant.

The following table illustrates the effect on earnings and earnings per common share for the year ended December 31, 2005, as if the Company had applied SFAS No. 123 and recognized compensation expense for all outstanding and unvested stock options based on the fair value at the date of grant:

	2005 (In thousands, except per share amounts)
Earnings on common stock, as reported	$ 274,398
Stock-based compensation expense included in reported earnings, net of related tax effects of $1	2
Total stock-based compensation expense determined under fair value method for all awards, net of related tax effects	(471)
Pro forma earnings on common stock	$ 273,929

Earnings per common share – basic – as reported	$ 1.54
Earnings per common share – basic – pro forma	$ 1.54
Earnings per common share – diluted – as reported	$ 1.53
Earnings per common share – diluted – pro forma	$ 1.53

For more information on the Company's stock-based compensation, see Note 14.

Use of estimates

The preparation of financial statements in conformity with accounting principles generally accepted in the United States of America requires the Company to make estimates and assumptions that affect the reported amounts of assets and liabilities, and disclosure of contingent assets and liabilities at the date of the financial statements, as well as the reported amounts of revenues and expenses during the reporting period. Estimates are used for items such as impairment testing of long-lived assets, goodwill and natural gas and oil properties; fair values of acquired assets and liabilities under the purchase method of accounting; natural gas and oil reserves; aggregate reserves; property depreciable lives; tax provisions; uncollectible accounts; environmental and other loss contingencies; accumulated provision for revenues subject to refund; costs on construction contracts; unbilled revenues; actuarially determined benefit costs; asset retirement obligations; the valuation of stock-based compensation; and the fair value of derivative instruments. As additional information becomes available, or actual amounts are determinable, the recorded estimates are revised. Consequently, operating results can be affected by revisions to prior accounting estimates.

Cash flow information

Cash expenditures for interest and income taxes were as follows:

Years ended December 31,	2007	2006	2005
		(In thousands)	
Interest, net of amount capitalized	$ 74,404	$ 65,850	$ 47,902
Income taxes	$ 214,573	$ 105,317	$ 106,771

Income taxes paid for the year ended December 31, 2007, increased from the amount paid for the years ended December 31, 2006 and 2005, primarily due to higher estimated quarterly tax payments due in large part to the gain on the sale of the domestic independent power production assets as discussed in Note 3.

New accounting standards

FIN 48 In July 2006, the FASB issued FIN 48. FIN 48 clarifies the application of SFAS No. 109 by defining a criterion that an individual tax position must meet for any part of the benefit of that position to be recognized in an enterprise's financial statements. The criterion allows for recognition in the financial statements of a tax position when it is more likely than not that the position will be sustained upon examination. FIN 48 was effective for the Company on January 1, 2007. The adoption of FIN 48 did not have a material effect on the Company's financial position or results of operations. For more information on the implementation of FIN 48, see Note 15.

SFAS No. 157 In September 2006, the FASB issued SFAS No. 157. SFAS No. 157 defines fair value, establishes a framework for measuring fair value and expands disclosures about fair value measurements. The standard applies under other accounting pronouncements that require or permit fair value measurements with certain exceptions. SFAS No. 157 was effective for the Company on January 1, 2008. The adoption of SFAS No. 157 did not have a material effect on the Company's financial position or results of operations.

SFAS No. 159 In February 2007, the FASB issued SFAS No. 159. SFAS No. 159 permits entities to choose to measure many financial instruments and certain other items at fair value that are not currently required to be measured at fair value. The standard also establishes presentation and disclosure requirements designed to facilitate comparisons between entities that choose different measurement attributes for similar types of assets and liabilities. SFAS No. 159 was effective for the Company on January 1, 2008, and at adoption, the Company elected to measure its investments in certain fixed-income and equity securities at fair value in accordance with SFAS No. 159. These investments prior to January 1, 2008, were accounted for as available-for-sale investments and recorded at fair value with any unrealized gains or losses, net of income taxes, recorded in accumulated other comprehensive income (loss) on the Consolidated Balance Sheets until realized. Upon the adoption of SFAS No. 159, the unrealized gain on the available-for-sale investments of $405,000 (after tax) was recorded as an increase to the January 1, 2008, balance of retained earnings. The adoption of SFAS No. 159 did not have a material effect on the Company's financial position or results of operations.

SFAS No. 141 (revised) In December 2007, the FASB issued SFAS No. 141 (revised). SFAS No. 141 (revised) requires an acquirer to recognize and measure the assets acquired, liabilities assumed and any noncontrolling interests in the acquiree at the acquisition date, measured at their fair values as of that date, with limited exception. In addition, SFAS No. 141 (revised) requires that acquisition-related costs will be generally expensed as incurred. SFAS No. 141 (revised) also expands the disclosure requirements for business combinations. SFAS No. 141 (revised) will be effective for the Company on January 1, 2009. The Company is evaluating the effects of the adoption of SFAS No. 141 (revised).

SFAS No. 160 In December 2007, the FASB issued SFAS No. 160. SFAS No. 160 establishes accounting and reporting standards for the noncontrolling interest in a subsidiary and for the deconsolidation of a subsidiary. SFAS No. 160 will be effective for the Company on January 1, 2009. The Company is evaluating the effects of the adoption of SFAS No. 160.

Comprehensive income

Comprehensive income is the sum of net income as reported and other comprehensive income (loss). The Company's other comprehensive income (loss) resulted from gains (losses) on derivative instruments qualifying as hedges, pension liability adjustments, foreign currency translation adjustments and gains on available-for-sale investments. For more information on derivative instruments, see Note 7.

The components of other comprehensive income (loss), and their related tax effects for the years ended December 31, 2007, 2006 and 2005, were as follows:

	2007	2006	2005
		(In thousands)	
Other comprehensive income (loss):			
Net unrealized gain (loss) on derivative instruments qualifying as hedges:			
Net unrealized gain (loss) on derivative instruments arising during the period, net of tax of $3,989, $12,359 and $(16,391) in 2007, 2006 and 2005, respectively	$ 6,508	$ 19,743	$ (26,167)
Less: Reclassification adjustment for gain (loss) on derivative instruments included in net income, net of tax of $12,504, $(16,194) and $(2,734) in 2007, 2006 and 2005, respectively	20,013	(25,867)	(4,367)
Net unrealized gain (loss) on derivative instruments qualifying as hedges	(13,505)	45,610	(21,800)
Pension liability adjustment, net of tax of $1,835, $1,122 and $353 in 2007, 2006 and 2005, respectively	3,012	1,761	574
Foreign currency translation adjustment, net of tax of $3,606 in 2007	7,177	(1,585)	(1,099)
Net unrealized gain on available-for-sale			

investments, net of tax of $270 in 2007	405	---	---
Total other comprehensive income (loss)	$ (2,911)	$ 45,786	$ (22,325)

The after-tax components of accumulated other comprehensive loss as of December 31, 2007, 2006 and 2005, were as follows:

	Net Unrealized Gain (Loss) on Derivative Instruments Qualifying as Hedges	Pension Liability Adjustment	Foreign Currency Translation Adjustment	Net Unrealized Gain on Available-for-sale Investments	Total Accumulated Other Comprehensive Loss
	(In thousands)				
Balance at December 31, 2005	$ (26,167)	$ (7,651)	$ 2	$ ---	$ (33,816)
Balance at December 31, 2006	$ 19,443	$ (24,342)	$ (1,583)	$ ---	$ (6,482)
Balance at December 31, 2007	$ 5,938	$ (21,330)	$ 5,594	$ 405	$ (9,393)

NOTE 2 – ACQUISITIONS

In 2007, the Company acquired construction materials and contracting businesses in North Dakota, Texas and Wyoming, a construction services business in Nevada, and Cascade, a natural gas distribution business, as discussed below. The total purchase consideration for these businesses and properties and purchase price adjustments with respect to certain other acquisitions made prior to 2007, consisting of the Company's common stock and cash and the outstanding indebtedness of Cascade, was $526.3 million.

On July 2, 2007, the acquisition of Cascade was finalized and Cascade became an indirect wholly owned subsidiary of the Company. The acquisition of Cascade was funded with cash (largely proceeds from the sale of the domestic independent power production assets) and debt. Cascade's natural gas service areas are in Washington and Oregon.

In 2006, the Company acquired a construction services business in Nevada, natural gas and oil production properties in Wyoming, and construction materials and contracting businesses in California and Washington, none of which was material. The total purchase consideration for these businesses and properties and purchase price adjustments with respect to certain other acquisitions made prior to 2006, consisting of the Company's common stock and cash, was $120.6 million.

In 2005, the Company acquired construction services businesses in Nevada, natural gas and oil production properties in southern Texas and construction materials and contracting businesses in Idaho, Iowa and Oregon, none of which was material. The total purchase consideration for these businesses and properties and purchase price adjustments with respect to certain other acquisitions acquired prior to 2005, consisting of the Company's common stock and cash, was $245.2 million.

The above acquisitions were accounted for under the purchase method of accounting and, accordingly, the acquired assets and liabilities assumed have been preliminarily recorded at their respective fair values as of the date of acquisition. On certain of the above acquisitions made in 2007, final fair market values are pending the completion of the review of the relevant assets and liabilities as of the acquisition date. The results of operations of the acquired businesses and properties are included in the financial statements since the date of each acquisition. Pro forma financial amounts reflecting the effects of the above acquisitions are not presented, as such acquisitions were not material to the Company's financial position or results of operations.

NOTE 3 – DISCONTINUED OPERATIONS

Innovatum, a component of the pipeline and energy services segment, specialized in cable and pipeline magnetization and location. During the third quarter of 2006, the Company initiated a plan to sell Innovatum because the Company determined that Innovatum is a non-strategic asset. During the fourth quarter of 2006, the stock and a portion of the assets of Innovatum were sold and the Company sold the remaining assets of Innovatum on January 23, 2008. The loss on disposal of Innovatum was not material.

During the fourth quarter of 2006, the Company initiated a plan to sell certain of the domestic assets of Centennial Resources. The plan to sell was based on the increased market demand for independent power production assets, combined with the Company's desire to efficiently fund future capital needs. The results of operations of these assets were shown in continuing operations in the Company's financial statements in the Company’s 2006 Annual Report on Form 10-K as the Company intended to have significant continuing involvement with these assets in the form of continuing existing operation and maintenance agreements between CEM and these assets after the sale.

The Company subsequently committed to a plan to sell CEM due to strong interest in the operations of CEM during the bidding process for the domestic independent power production assets in the first quarter of 2007. As a result of the Company's commitment to a plan to sell CEM, the Company would no longer have significant continuing involvement in the operations of the other domestic independent power production assets after the sale. Therefore, in accordance with SFAS No. 144, the results of operations of the domestic independent power production assets, including CEM, are presented as discontinued operations.

On July 10, 2007, Centennial Resources sold its domestic independent power production business consisting of Centennial Power and CEM to Bicent Power LLC (formerly known as Montana Acquisition Company LLC). The transaction was valued at $636 million, which included the assumption of approximately $36 million of project-related debt. The gain on the sale of the assets, excluding the gain on the sale of Hartwell as discussed in Note 4, was approximately $85.4 million (after tax). A portion of the proceeds from the sale was used to pay a dividend to the Company. This dividend was then used to prepay, in part, the outstanding term loan indebtedness that was incurred by the Company to fund the Cascade acquisition. The remaining proceeds of the sale provided additional cash for growth opportunities.

In accordance with SFAS No. 144, the Company's consolidated financial statements and accompanying notes for prior periods have been restated to present the results of operations of Innovatum and the domestic independent power production assets as discontinued operations. In addition, the assets and liabilities of these operations were treated as held for sale, and as a result, no depreciation, depletion and amortization expense was recorded from the time each of the assets was classified as held for sale.

In accordance with SFAS No. 142, at the time the Company committed to the plan to sell each of the assets, the Company was required to test the respective assets for goodwill impairment. The fair value of Innovatum, a reporting unit for goodwill impairment testing, was estimated using the expected proceeds from the sale, which was estimated to be the current book value of the assets of Innovatum other than its goodwill. As a result, a goodwill impairment of $4.3 million (before tax) was recognized and recorded as part of discontinued operations, net of tax, in the Consolidated Statements of Income in the third quarter of 2006. There were no goodwill impairments associated with the other assets held for sale.

Operating results related to Innovatum for the years ended December 31, 2007, 2006 and 2005, were as follows:

	2007	2006	2005
		(In thousands)	
Operating revenues	$ 1,748	$ 1,827	$ 2,983
Loss from discontinued operations before income tax benefit	(210)	(5,994)	(1,506)
Income tax benefit	(316)	(3,834)	(731)
Income (loss) from discontinued operations, net of tax	$ 106	$ (2,160)	$ (775)

The income tax benefit for the year ended December 31, 2006, is larger than the customary relationship between the income tax benefit and the loss before tax due to a capital loss tax benefit (which reflects the effect of the $4.3 million and $4.0 million goodwill impairments in 2006 and 2004, respectively) resulting from the sale of the Innovatum stock.

Operating results related to the domestic independent power production assets for the years ended December 31, 2007, 2006 and 2005, were as follows:

	2007	2006	2005
		(In thousands)	
Operating revenues	$ 125,867	$ 66,145	$ 48,508
Income from discontinued operations (including gain on disposal in 2007 of $142.4 million) before income tax expense (benefit)	177,666	9,276	10,828
Income tax expense (benefit)	68,438	(863)	261
Income from discontinued operations, net of tax	$ 109,228	$ 10,139	$ 10,567

The income tax benefit for the year ended December 31, 2006, and the lower income tax expense for the year ended December 31, 2005, reflect a renewable electricity production tax credit of $4.4 million and $4.1 million, respectively.

Revenues at the former independent power production operations were recognized based on electricity delivered and capacity provided, pursuant to contractual commitments and, where applicable, revenues were recognized under EITF No. 91-6 ratably over the terms of the related contract. Arrangements with multiple revenue-generating activities were recognized under EITF No. 00-21 with the multiple deliverables divided into separate units of accounting based on specific criteria and revenues of the arrangements allocated to the separate units based on their relative fair values.

The carrying amounts of the major assets and liabilities related to the domestic independent power production assets held for sale, as well as the major assets and liabilities related to Innovatum, at December 31, 2007 and 2006, were as follows:

	2007	2006
	(In thousands)	
Cash and cash equivalents	$ ---	$ 1,878
Receivables, net	---	8,307
Inventories	179	490
Prepayments and other current assets	---	1,981
Total current assets held for sale	$ 179	$ 12,656
Net property, plant and equipment	$ ---	$ 390,679
Goodwill	---	11,167
Other intangible assets, net	---	7,162
Other	---	2,257
Total noncurrent assets held for sale	$ ---	$ 411,265
Accounts payable	$ ---	$ 11,557
Other accrued liabilities	---	3,343
Total current liabilities held for sale	$ ---	$ 14,900
Deferred income taxes	$ ---	$ 27,956
Other liabilities	---	2,577
Total noncurrent liabilities held for sale	$ ---	$ 30,533

NOTE 4 – EQUITY METHOD INVESTMENTS

Investments in companies in which the Company has the ability to exercise significant influence over operating and financial policies are accounted for using the equity method. The Company's equity method investments at December 31, 2007, include the Brazilian Transmission Lines.

In August 2006, MDU Brasil acquired ownership interests in companies owning three electric transmission lines. The interests involve the ENTE (13.3-percent ownership interest), ERTE (13.3-percent ownership interest) and ECTE (25-percent ownership interest) electric transmission lines, which are primarily in northeastern and southern Brazil. The contracts provide for revenues denominated in the Brazilian Real, annual inflation adjustments and change in tax law adjustments and have between 23 and 25 years remaining under the contracts. Alusa, Brascan and CEMIG hold the remaining ownership interests, with CELESC also having an ownership interest in ECTE. The functional currency for the Brazilian Transmission Lines is the Brazilian Real.

In February 2004, Centennial International acquired 49.99 percent of Carib Power. Carib Power, through a wholly owned subsidiary, owns a 225-MW natural gas-fired electric generating facility in Trinidad and Tobago. On February 26, 2007, the Company sold its interest in Carib Power. The sale did not have a significant effect on the Company's results of operations.

In September 2004, Centennial Resources, through indirect wholly owned subsidiaries, acquired a 50-percent ownership interest in Hartwell, which owns a 310-MW natural gas-fired electric generating facility near Hartwell, Georgia. On July 10, 2007, the Company sold its ownership interest in Hartwell, and realized a gain of $10.1 million ($6.1 million after tax) from the sale which is recorded in earnings from equity method investments on the Consolidated Statements of Income.

In June 2005, the Company completed the sale of its 49 percent interest in MPX to Petrobras, the Brazilian state-controlled energy company. The Company realized a gain of $15.6 million from the sale in 2005.

At December 31, 2007 and 2006, the Company's equity method investments had total assets of $398.4 million and $583.6 million, respectively, and long-term debt of $211.2 million and $321.5 million, respectively. The Company's investment in its equity method investments was approximately $59.0 million and $102.0 million, including undistributed earnings of $6.9 million and $8.5 million, at December 31, 2007 and 2006, respectively.

NOTE 5 – GOODWILL AND OTHER INTANGIBLE ASSETS

The changes in the carrying amount of goodwill for the year ended December 31, 2007, were as follows:

	Balance as of January 1, 2007	Goodwill Acquired During the Year*	Balance as of December 31, 2007
	(In thousands)		
Electric	$ ---	$ ---	$ ---
Natural gas distribution	---	171,129	171,129
Construction services	86,942	4,443	91,385
Pipeline and energy services	1,159	---	1,159
Natural gas and oil production	---	---	---
Construction materials and contracting	136,197	25,828	162,025
Other	---	---	---
Total	$ 224,298	$ 201,400	$ 425,698

*Includes purchase price adjustments that were not material related to acquisitions in a prior period.

The changes in the carrying amount of goodwill for the year ended December 31, 2006, were as follows:

	Balance as of January 1, 2006	Goodwill Acquired During the Year*	Balance as of December 31, 2006
		(In thousands)	
Electric	$ ---	$ ---	$ ---
Natural gas distribution	---	---	---
Construction services	80,970	5,972	86,942
Pipeline and energy services	1,159	---	1,159
Natural gas and oil production	---	---	---
Construction materials and contracting	133,264	2,933	136,197
Other	---	---	---
Total	$ 215,393	$ 8,905	$ 224,298

*Includes purchase price adjustments that were not material related to acquisitions in a prior period.

For more information on the goodwill impairment related to the discontinued operations at Innovatum in 2006, see Note 3.

Other amortizable intangible assets at December 31, 2007 and 2006, were as follows:

	2007	2006
	(In thousands)	
Customer relationships	$ 21,834	$ 13,030
Accumulated amortization	(4,444)	(1,890)
	17,390	11,140
Noncompete agreements	10,655	12,886
Accumulated amortization	(3,654)	(8,540)
	7,001	4,346
Acquired contracts	2,539	8,307
Accumulated amortization	(1,615)	(4,646)
	924	3,661
Other	3,404	5,062
Accumulated amortization	(927)	(1,407)
	2,477	3,655
Total	$ 27,792	$ 22,802

Amortization expense for intangible assets for the years ended December 31, 2007, 2006 and 2005, was $4.4 million, $4.3 million and $3.5 million, respectively. Estimated amortization expense for intangible assets is $5.7 million in 2008, $4.4 million in 2009, $3.4 million in 2010, $2.9 million in 2011, $2.7 million in 2012 and $8.7 million thereafter.

NOTE 6 – REGULATORY ASSETS AND LIABILITIES

The following table summarizes the individual components of unamortized regulatory assets and liabilities as of December 31:

	2007	2006
	(In thousands)	
Regulatory assets:		
Deferred income taxes	$ 43,866	$ 35,978
Pension and postretirement benefits	21,613	19,075

Natural gas supply derivatives	16,324	---
Long-term debt refinancing costs	10,605	11,232
Plant costs	4,930	13,254
Other	15,812	7,230
Total regulatory assets	113,150	86,769
Regulatory liabilities:		
Plant removal and decommissioning costs	89,991	85,087
Taxes refundable to customers	22,580	14,229
Deferred income taxes	17,630	18,019
Natural gas costs refundable through rate adjustments	11,568	7,516
Natural gas supply derivatives	5,631	---
Other	8,250	4,179
Total regulatory liabilities	155,650	129,030
Net regulatory position	$ (42,500)	$ (42,261)

As of December 31, 2007, a large portion of the Company's regulatory assets, other than certain deferred income taxes, was being reflected in rates charged to customers and is being recovered over the next 1 to 15 years. A portion of the Company's regulatory assets are not earning a return; however, these regulatory assets are expected to be recovered from customers in future rates.

If, for any reason, the Company's regulated businesses cease to meet the criteria for application of SFAS No. 71 for all or part of their operations, the regulatory assets and liabilities relating to those portions ceasing to meet such criteria would be removed from the balance sheet and included in the statement of income as an extraordinary item in the period in which the discontinuance of SFAS No. 71 occurs.

NOTE 7 – DERIVATIVE INSTRUMENTS
Derivative instruments, including certain derivative instruments embedded in other contracts, are required to be recorded on the balance sheet as either an asset or liability measured at fair value. Changes in the derivative instrument's fair value are recognized currently in earnings unless specific hedge accounting criteria are met. Accounting for qualifying hedges allows derivative gains and losses to offset the related results on the hedged item in the income statement and requires that a company must formally document, designate and assess the effectiveness of transactions that receive hedge accounting treatment.

In the event a derivative instrument being accounted for as a cash flow hedge does not qualify for hedge accounting because it is no longer highly effective in offsetting changes in cash flows of a hedged item; if the derivative instrument expires or is sold, terminated or exercised; or if management determines that designation of the derivative instrument as a hedge instrument is no longer appropriate, hedge accounting would be discontinued and the derivative instrument would continue to be carried at fair value with changes in its fair value recognized in earnings. In these circumstances, the net gain or loss at the time of discontinuance of hedge accounting would remain in accumulated other comprehensive income (loss) until the period or periods during which the hedged forecasted transaction affects earnings, at which time the net gain or loss would be reclassified into earnings. In the event a cash flow hedge is discontinued because it is unlikely that a forecasted transaction will occur, the derivative instrument would continue to be carried on the balance sheet at its fair value, and gains and losses that had accumulated in other comprehensive income (loss) would be recognized immediately in earnings. In the event of a sale, termination or extinguishment of a foreign currency derivative, the resulting gain or loss would be recognized immediately in earnings. The Company's policy requires approval to terminate a derivative instrument prior to its original maturity. As of December 31, 2007, the Company had no outstanding foreign currency or interest rate hedges.

Cascade core
At December 31, 2007, Cascade held natural gas swap agreements which were not designated as hedges.

Cascade utilizes natural gas swap agreements to manage a portion of the market risk associated with fluctuations in the price of natural gas on its forecasted purchases of natural gas for core customers in accordance with authority granted by the WUTC and OPUC. Core customers consist of residential, commercial and smaller industrial customers. The fair value of the derivative instrument must be estimated as of the end of each reporting period and is recorded on the Consolidated Balance Sheets as an asset or a liability. Cascade applies SFAS No. 71 and records periodic changes in the fair market value of the derivative instruments on the Consolidated Balance Sheets as a regulatory asset or a regulatory liability, and settlements of these arrangements are expected to be recovered through the purchased gas cost adjustment mechanism. Under the terms of these arrangements, Cascade will either pay or receive settlement payments based on the difference between the fixed strike price and the monthly index price applicable to each contract.

Fidelity and Cascade non-core

At December 31, 2007, Fidelity held natural gas and oil swap and collar derivative instruments designated as cash flow hedging instruments. Cascade held natural gas swap derivative instruments designated as cash flow hedging instruments.

Fidelity utilizes natural gas and oil price swap and collar agreements to manage a portion of the market risk associated with fluctuations in the price of natural gas and oil on its forecasted sales of natural gas and oil production. Cascade utilizes natural gas swap agreements to manage a portion of the market risk associated with fluctuations in the price of natural gas on its forecasted purchases of natural gas for non-core customers. Cascade's non-core customers, who are not covered by the purchased gas cost adjustment mechanism, are generally large industrial, electric generation and institutional customers. Each of the price swap and collar agreements was designated as a cash flow hedge of the forecasted sale of the related production or as a cash flow hedge of the forecasted purchase of the related commodity.

The fair value of the hedging instruments must be estimated as of the end of each reporting period and is recorded on the Consolidated Balance Sheets as an asset or a liability. Changes in the fair value attributable to the effective portion of hedging instruments, net of tax, are recorded in stockholders' equity as a component of accumulated other comprehensive income (loss). At the date the natural gas or oil quantities are settled, the amounts accumulated in other comprehensive income (loss) are reported in the Consolidated Statements of Income. To the extent that the hedges are not effective, the ineffective portion of the changes in fair market value is recorded directly in earnings. The proceeds received for natural gas and oil production and the amount paid for natural gas purchases are also generally based on market prices.

For the years ended December 31, 2007 and 2005, the amount of hedge ineffectiveness was immaterial. In the second quarter of 2006, Fidelity's oil collar agreements became ineffective and no longer qualified for hedge accounting. The oil hedges became ineffective as the physical price received no longer correlated to the hedge price due to the widening of regional basis differentials on the price of the physical production received. The ineffectiveness related to these collar agreements resulted in a loss of approximately $138,000 (before tax) for the year ended December 31, 2006, that was recorded in operation and maintenance expense. The ineffective collar agreements expired by December 31, 2006. The amount of hedge ineffectiveness on Fidelity's remaining hedges was immaterial for the year ended December 31, 2006.

For the years ended December 31, 2007, 2006 and 2005, there were no components of the derivative instruments' gain or loss excluded from the assessment of hedge effectiveness. Gains and losses must be reclassified into earnings as a result of the discontinuance of cash flow hedges if it is probable that the original forecasted transactions will not occur. There were no such reclassifications into earnings as a result of the discontinuance of hedges.

Gains and losses on derivative instruments that are reclassified from accumulated other comprehensive income (loss) to current-period earnings are included in the line item in which the hedged item is recorded. As of December 31, 2007, the maximum term of the swap and collar agreements, in which the exposure to the variability in future cash flows for forecasted transactions is being hedged, is 12 months. The Company estimates that over the next 12 months, net gains of approximately $6.2 million (after tax) will be reclassified from accumulated other comprehensive loss into earnings, subject to changes in natural gas and oil market prices, as the hedged transactions affect earnings.

NOTE 8 – FAIR VALUE OF OTHER FINANCIAL INSTRUMENTS
The estimated fair value of the Company's long-term debt is based on quoted market prices of the same or similar issues. The estimated fair values of the Company's natural gas and oil price swap and collar agreements reflect the estimated amounts the Company would receive or pay to terminate the contracts at the reporting date based upon quoted market prices of comparable contracts.

The estimated fair value of the Company's long-term debt at December 31 was as follows:

	2007		2006	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
		(In thousands)		
Long-term debt	$ 1,308,463	$ 1,293,863	$ 1,254,582	$ 1,247,439
Commodity derivative agreements – current asset	$ 12,740	$ 12,740	$ 32,101	$ 32,101
Commodity derivative agreements – current liability	$ (14,799)	$ (14,799)	$ ---	$ ---
Commodity derivative agreements – noncurrent asset	$ 3,419	$ 3,419	$ ---	$ ---
Commodity derivative agreements – noncurrent liability	$ (2,570)	$ (2,570)	$ ---	$ ---

The carrying amounts of the Company's remaining financial instruments included in current assets and current liabilities approximate their fair values.

NOTE 9 – SHORT-TERM BORROWINGS
Cascade has a revolving credit agreement with various banks totaling $50 million with certain provisions allowing for increased borrowings, up to a maximum of $75 million. The $50 million credit agreement expires on December 28, 2012, with provisions allowing for an extension of up to two years upon consent of the banks. Cascade also has a $20 million uncommitted line of credit which may be terminated by the bank or Cascade at any time. There was $1.7 million outstanding under the Cascade credit agreements at December 31, 2007. The borrowings are classified as short-term borrowings as Cascade intends to repay the borrowings within one year. The weighted average interest rate for borrowings outstanding at December 31, 2007, was 4.75 percent. As of December 31, 2007, there were outstanding letters of credit, as discussed in Note 20, of which $1.9 million reduced amounts available under the $50 million credit agreement.

In order to borrow under Cascade's $50 million credit agreement, Cascade must be in compliance with the applicable covenants and certain other conditions. This includes a covenant not to permit, at any time, the ratio of total debt to total capitalization to be greater than 65 percent. Cascade was in compliance with these covenants and met the required conditions at December 31, 2007.

Cascade's $50 million credit agreement contains cross-default provisions. These provisions state that if Cascade fails to make any payment with respect to any indebtedness or contingent obligation, in excess of a specified amount, under any agreement that causes such indebtedness to be due prior to its stated maturity or the contingent obligation to become payable, the agreement will be in default. Certain of Cascade's financing agreements and Cascade's practices limit the amount of subsidiary indebtedness.

NOTE 10 – LONG-TERM DEBT AND INDENTURE PROVISIONS
Long-term debt outstanding at December 31 was as follows:

	2007	2006
	(In thousands)	

First mortgage bonds and notes:		
Secured Medium-Term Notes, Series A, at a weighted average rate of 6.48%, due on dates ranging from October 1, 2008 to April 1, 2012	$ 20,500	$ 27,000
Senior Notes, 5.98%, due December 15, 2033	30,000	30,000
Total first mortgage bonds and notes	50,500	57,000
Senior Notes at a weighted average rate of 5.64%, due on dates ranging from June 27, 2008 to March 8, 2037	1,064,000	1,064,500
Medium-Term Notes, at a weighted average rate of 7.72% due on dates ranging from September 4, 2012 to March 16, 2029	81,000	---
Commercial paper at a weighted average rate of 4.95%, supported by revolving credit agreements	61,000	122,850
Other notes, at a weighted average rate of 5.24% due on dates ranging from September 1, 2020 to February 1, 2035	43,679	---
Term credit agreements at a weighted average rate of 5.88%, due on dates ranging from July 1, 2008 to August 31, 2015	8,286	10,290
Discount	(2)	(58)
Total long-term debt	1,308,463	1,254,582
Less current maturities	161,682	84,034
Net long-term debt	$ 1,146,781	$ 1,170,548

The amounts of scheduled long-term debt maturities for the five years and thereafter following December 31, 2007, aggregate $161.7 million in 2008; $73.4 million in 2009; $7.3 million in 2010; $128.0 million in 2011; $135.5 million in 2012 and $802.6 million thereafter.

Certain debt instruments of the Company and its subsidiaries, including those discussed below, contain restrictive covenants, all of which the Company and its subsidiaries were in compliance with at December 31, 2007.

MDU Resources Group, Inc. The Company has a revolving credit agreement with various banks totaling $125 million (with provision for an increase, at the option of the Company on stated conditions, up to a maximum of $150 million). There were no amounts outstanding under the credit agreement at December 31, 2007 and 2006. The credit agreement supports the Company's $100 million commercial paper program. Under the Company's commercial paper program, $61.0 million and $25.8 million were outstanding at December 31, 2007 and 2006, respectively. The commercial paper borrowings are classified as long-term debt as they are intended to be refinanced on a long-term basis through continued commercial paper borrowings (supported by the credit agreement, which expires in June 2011).

In order to borrow under the Company's credit agreement, the Company must be in compliance with the applicable covenants and certain other conditions, including covenants not to permit, as of the end of any fiscal quarter, (A) the ratio of funded debt to total capitalization (determined on a consolidated basis) to be greater than 65 percent or (B) the ratio of funded debt to capitalization (determined with respect to the Company alone, excluding its subsidiaries) to be greater than 65 percent. Also included is a covenant that does not permit the ratio of the Company's earnings before interest, taxes, depreciation and amortization to interest expense (determined with respect to the Company alone, excluding its subsidiaries), for the 12-month period ended each fiscal quarter, to be less than 2.5 to 1. Other covenants include restrictions on the sale of certain assets and on the making of certain investments. The Company was in compliance with these covenants and met the required conditions at December 31, 2007. In the event the Company does not comply with the applicable covenants and other conditions, alternative sources of funding may need to be pursued.

There are no credit facilities that contain cross-default provisions between the Company and any of its subsidiaries.

The Company's issuance of first mortgage debt is subject to certain restrictions imposed under the terms and conditions of its Mortgage. Generally, those restrictions require the Company to fund $1.43 of unfunded property or use $1.00 of refunded bonds for each dollar of indebtedness incurred under the Mortgage and, in some cases, to certify to the trustee that annual earnings (pretax and before interest charges), as defined in the Mortgage, equal at least two times its annualized first mortgage bond interest costs. Under the more restrictive of the tests, as of December 31, 2007, the Company could have issued approximately $544 million of additional first mortgage bonds.

Approximately $549.8 million in net book value of the Company’s electric and natural gas distribution properties at December 31, 2007, with certain exceptions, are subject to the lien of the Mortgage and to the junior lien of the Indenture.

MDU Energy Capital, LLC On August 14, 2007, MDU Energy Capital entered into a $125 million master shelf agreement (dated as of August 9, 2007). Under the terms of the master shelf agreement, $85.0 million was outstanding at December 31, 2007.

The master shelf agreement contains customary covenants and provisions, including covenants of MDU Energy Capital not to permit (i) the ratio of its total debt (on a consolidated basis) to adjusted total capitalization to be greater than 70 percent, or (ii) the ratio of subsidiary debt to subsidiary capitalization to be greater than 65 percent. The agreement also includes a covenant requiring the ratio of MDU Energy Capital earnings before interest and taxes to interest expense (on a consolidated basis), for the 12-month period ended each fiscal quarter (commencing with the fiscal quarter ended September 30, 2007), to be greater than 1.5 to 1. MDU Energy Capital was in compliance with these covenants and met the required conditions at December 31, 2007. In addition, payment obligations under the master shelf agreement may be accelerated upon the occurrence of an event of default (as described in the agreement). MDU Energy Capital may incur additional indebtedness under the master shelf agreement, up to a total of $125 million, until the earlier of August 14, 2010, or such time as the agreement is terminated by either of the parties thereto.

Centennial Energy Holdings, Inc. Centennial has a revolving credit agreement and an uncommitted line of credit with various banks and institutions totaling $425 million with certain provisions allowing for increased borrowings. These credit agreements support Centennial's $400 million commercial paper program. There were no outstanding borrowings under the Centennial credit agreements at December 31, 2007 and 2006. Under the Centennial commercial paper program, there was no amount outstanding at December 31, 2007, and $97.1 million outstanding at December 31, 2006. Centennial commercial paper borrowings are classified as long-term debt as they are intended to be refinanced on a long-term basis through continued Centennial commercial paper borrowings (supported by Centennial credit agreements). The revolving credit agreement is for $400 million, which includes a provision for an increase, at the option of Centennial on stated conditions, up to a maximum of $450 million and expires on December 13, 2012. The uncommitted line of credit for $25 million may be terminated by the bank at any time. As of December 31, 2007, $56.6 million of letters of credit were outstanding, as discussed in Note 20, of which $44.0 million reduced amounts available under these agreements.

Centennial has an uncommitted long-term master shelf agreement that allows for borrowings of up to $550 million. Under the terms of the master shelf agreement, $418.5 million and $539.5 million were outstanding at December 31, 2007 and 2006, respectively. The ability to request additional borrowings under this master shelf agreement expires on May 8, 2009.

In order to borrow under Centennial's credit agreements and the Centennial uncommitted long-term master shelf agreement, Centennial and certain of its subsidiaries must be in compliance with the applicable covenants and certain other conditions, including covenants not to permit, as of the end of any fiscal quarter, the ratio of total debt to total capitalization to be greater than 65 percent (for the $400 million credit agreement) and 60 percent (for the master shelf agreement). The master shelf agreement also includes a covenant that does not permit the ratio of Centennial's earnings before interest, taxes, depreciation and amortization to interest expense, for the 12-month period ended each fiscal quarter, to be less than 1.75 to 1. Other covenants include minimum consolidated net worth, limitation on priority debt and restrictions on the sale of certain assets and on the making of certain loans and investments. Centennial and such subsidiaries were in compliance with these covenants and met the required conditions at December 31, 2007. In the event Centennial or such subsidiaries do not comply with the applicable covenants and other conditions, alternative sources of funding may need to be pursued.

Certain of Centennial's financing agreements contain cross-default provisions. These provisions state that if Centennial or any subsidiary of Centennial fails to make any payment with respect to any indebtedness or contingent obligation, in excess of a specified amount, under any agreement that causes such indebtedness to be due prior to its stated maturity or the contingent obligation to become payable, the applicable agreements will be in default. Certain of Centennial's financing agreements and Centennial's practices limit the amount of subsidiary indebtedness.

Williston Basin Interstate Pipeline Company Williston Basin has an uncommitted long-term master shelf agreement that allows for borrowings up to $100 million. Under the terms of the master shelf agreement, $80.0 million was outstanding at December 31, 2007 and 2006. The ability to request additional borrowings under this master shelf agreement expires on December 20, 2008.

In order to borrow under its uncommitted long-term master shelf agreement, Williston Basin must be in compliance with the applicable covenants and certain other conditions, including covenants not to permit, as of the end of any fiscal quarter, the ratio of total debt to total capitalization to be greater than 55 percent. Other covenants include limitation on priority debt and some restrictions on the sale of certain assets and the making of certain investments. Williston Basin was in compliance with these covenants and met the required conditions at December 31, 2007. In the event Williston Basin does not comply with the applicable covenants and other conditions, alternative sources of funding may need to be pursued.

NOTE 11 – ASSET RETIREMENT OBLIGATIONS

The Company records obligations related to the plugging and abandonment of natural gas and oil wells, decommissioning of certain electric generating facilities, reclamation of certain aggregate properties and certain other obligations associated with leased properties.

A reconciliation of the Company's liability, which is included in other liabilities, for the years ended December 31 was as follows:

	2007	2006
	(In thousands)	
Balance at beginning of year	$ 56,179	$ 42,857
Liabilities incurred	4,149	4,878
Liabilities acquired	652	1,118
Liabilities settled	(5,896)	(2,963)
Accretion expense	3,081	3,093
Revisions in estimates	6,100	6,321
Other	188	875
Balance at end of year	$ 64,453	$ 56,179

The Company believes that any expenses under SFAS No. 143 and FIN 47 as they relate to regulated operations will be recovered in rates over time and, accordingly, defers such expenses as regulatory assets.

The fair value of assets that are legally restricted for purposes of settling asset retirement obligations at December 31, 2007 and 2006, was $5.8 million and $5.5 million, respectively.

NOTE 12 – PREFERRED STOCKS
Preferred stocks at December 31 were as follows:

	2007	2006
	(Dollars in thousands)	
Authorized:		
Preferred –		
500,000 shares, cumulative, par value $100, issuable in series		
Preferred stock A –		
1,000,000 shares, cumulative, without par value, issuable in series (none outstanding)		
Preference –		
500,000 shares, cumulative, without par value, issuable in series (none outstanding)		
Outstanding:		
4.50% Series – 100,000 shares	$10,000	$10,000
4.70% Series – 50,000 shares	5,000	5,000
Total preferred stocks	$15,000	$15,000

The 4.50% Series and 4.70% Series preferred stocks outstanding are subject to redemption, in whole or in part, at the option of the Company with certain limitations on 30 days notice on any quarterly dividend date at a redemption price, plus accrued dividends, of $105 per share and $102 per share, respectively.

In the event of a voluntary or involuntary liquidation, all preferred stock series holders are entitled to $100 per share, plus accrued dividends.

The affirmative vote of two-thirds of a series of the Company's outstanding preferred stock is necessary for amendments to the Company's charter or bylaws that adversely affect that series; creation of or increase in the amount of authorized stock ranking senior to that series (or an affirmative majority vote where the authorization relates to a new class of stock that ranks on parity with such series); a voluntary liquidation or sale of substantially all of the Company's assets; a merger or consolidation, with certain exceptions; or the partial retirement of that series of preferred stock when all dividends on that series of preferred stock have not been paid. The consent of the holders of a particular series is not required for such corporate actions if the equivalent vote of all outstanding series of preferred stock voting together has consented to the given action and no particular series is affected differently than any other series.

Subject to the foregoing, the holders of common stock exclusively possess all voting power. However, if cumulative dividends on preferred stock are in arrears, in whole or in part, for one year, the holders of preferred stock would obtain the right to one vote per share until all dividends in arrears have been paid and current dividends have been declared and set aside.

NOTE 13 – COMMON STOCK
On May 11, 2006, the Company's Board of Directors approved a three-for-two common stock split to be effected in the form of a 50 percent common stock dividend. The additional shares of common stock were distributed on July 26, 2006, to common stockholders of record on July 12, 2006. Certain common stock information appearing in the accompanying consolidated financial statements has been restated in accordance with accounting principles generally accepted in the United States of America to give retroactive effect to the stock split. Additionally, preference share

purchase rights have been appropriately adjusted to reflect the effects of the split.

In 1998, the Company's Board of Directors declared, pursuant to a stockholders' rights plan, a dividend of one preference share purchase right (right) for each outstanding share of the Company's common stock. Each right becomes exercisable, upon the occurrence of certain events, for four-ninths of one one-thousandth of a share of Series B Preference Stock of the Company, without par value, at an exercise price of $125, subject to certain adjustments. The rights are currently not exercisable and will be exercisable only if a person or group (acquiring person) either acquires ownership of 15 percent or more of the Company's common stock or commences a tender or exchange offer that would result in ownership of 15 percent or more. In the event the Company is acquired in a merger or other business combination transaction or 50 percent or more of its consolidated assets or earnings power are sold, each right entitles the holder to receive, upon the exercise thereof at the then current exercise price of the right multiplied by the number of four-ninths of one one-thousandth of a share of Series B Preference Stock for which a right is then exercisable, in accordance with the terms of the rights agreement, such number of shares of common stock of the acquiring person having a market value of twice the then current exercise price of the right. The rights, which expire on December 31, 2008, are redeemable in whole, but not in part, for a price of $.00444 per right, at the Company's option at any time until any acquiring person has acquired 15 percent or more of the Company's common stock.

The Stock Purchase Plan provides interested investors the opportunity to make optional cash investments and to reinvest all or a percentage of their cash dividends in shares of the Company's common stock. The K-Plan is partially funded with the Company's common stock. From July 2006 through March 2007, the Stock Purchase Plan and K-Plan, with respect to Company stock, were funded with shares of authorized but unissued common stock. From January 2005 through June 2006, and April 2007 through December 2007, purchases of shares of common stock on the open market were used to fund the Stock Purchase Plan and K-Plan. At December 31, 2007, there were 20.6 million shares of common stock reserved for original issuance under the Stock Purchase Plan and K-Plan.

NOTE 14 – STOCK-BASED COMPENSATION

On January 1, 2006, the Company adopted SFAS No. 123 (revised) and on January 1, 2003, adopted SFAS No. 123. For a discussion of the adoption of SFAS No. 123 (revised) and SFAS No. 123, see Note 1.

The Company has several stock-based compensation plans and is authorized to grant options, restricted stock and stock for up to 17.1 million shares of common stock and has granted options, restricted stock and stock of 6.9 million shares through December 31, 2007. The Company generally issues new shares of common stock to satisfy stock option exercises, restricted stock, stock and performance share awards.

Total stock-based compensation expense for the year ended December 31, 2007, was $4.7 million, net of income taxes of $3.1 million. Total stock-based compensation for the year ended December 31, 2006, was $3.5 million, net of income taxes of $2.2 million.

As of December 31, 2007, total remaining unrecognized compensation expense related to stock-based compensation was approximately $4.7 million (before income taxes) which will be amortized over a weighted average period of 1.5 years.

Stock options

The Company has stock option plans for directors, key employees and employees. The Company has not granted stock options since 2003. Options granted to key employees automatically vest after nine years, but the plan provides for accelerated vesting based on the attainment of certain performance goals or upon a change in control of the Company, and expire 10 years after the date of grant. Options granted to directors and employees vest at the date of grant and three years after the date of grant, respectively, and expire 10 years after the date of grant.

The fair value of each option outstanding was estimated on the date of grant using the Black-Scholes option-pricing model.

A summary of the status of the stock option plans at December 31, 2007, and changes during the year then ended was as follows:

	Number of Shares	Weighted Average Exercise Price
Balance at beginning of year	2,311,546	$ 13.11
Forfeited	(39,352)	12.97
Exercised	(776,286)	13.15
Balance at end of year	1,495,908	13.09
Exercisable at end of year	1,468,940	$ 13.08

Summarized information about stock options outstanding and exercisable as of December 31, 2007, was as follows:

	Options Outstanding				Options Exercisable		
Range of Exercisable Prices	Number Outstanding	Remaining Contractual Life in Years	Weighted Average Exercise Price	Aggregate Intrinsic Value (000's)	Number Exercisable	Weighted Average Exercise Price	Aggregate Intrinsic Value (000's)
$ 8.88 – 11.00	135,776	.5	$9.71	$2,431	135,776	$9.71	$2,431
11.01 – 14.00	1,262,944	3.2	13.20	18,199	1,241,409	13.20	17,891
14.01 – 17.13	97,188	3.2	16.39	1,090	91,755	16.40	1,028
Balance at end of year	1,495,908	2.9	$13.09	$21,720	1,468,940	$13.08	$21,350

The aggregate intrinsic value in the preceding table represents the total intrinsic value (before income taxes), based on the Company's stock price on December 31, 2007, which would have been received by the option holders had all option holders exercised their options as of that date.

The weighted average remaining contractual life of options exercisable was 2.9 years at December 31, 2007.

The Company received cash of $10.2 million and $4.5 million from the exercise of stock options for the years ended December 31, 2007 and 2006, respectively. The aggregate intrinsic value of options exercised during the years ended December 31, 2007 and 2006, was $11.2 million and $4.4 million, respectively.

Restricted stock awards

Prior to 2002, the Company granted restricted stock awards under a long-term incentive plan. The restricted stock awards granted vest at various times ranging from one year to nine years from the date of issuance, but certain grants may vest early based upon the attainment of certain performance goals or upon a change in control of the Company. The grant-date fair value is the market price of the Company's stock on the grant date.

A summary of the status of the restricted stock awards for the year ended December 31, 2007, was as follows:

	Number of Shares	Weighted Average Grant-Date Fair Value
Nonvested at beginning of period	32,117	$13.22
Vested	---	---

Forfeited	(5,384)	13.22
Nonvested at end of period	26,733	$13.22

The fair value of restricted stock awards that vested during the year ended December 31, 2006, was $1.8 million.

Stock awards
Nonemployee directors may receive shares of common stock instead of cash in payment for directors' fees under the nonemployee director stock compensation plan. There were 48,228 shares with a fair value of $1.5 million and 50,627 shares with a fair value of $1.3 million issued under this plan during the years ended December 31, 2007 and 2006, respectively.

Performance share awards
Since 2003, key employees of the Company have been awarded performance share awards each year. Entitlement to performance shares is based on the Company's total shareholder return over designated performance periods as measured against a selected peer group.

Target grants of performance shares outstanding at December 31, 2007, were as follows:

Grant Date	Performance Period	Target Grant of Shares
February 2005	2005-2007	256,081
February 2006	2006-2008	184,000
February 2007	2007-2009	184,418

Participants may earn from zero to 200 percent of the target grant of shares based on the Company's total shareholder return relative to that of the selected peer group. Compensation expense is based on the grant-date fair value. The grant-date fair value of performance share awards granted during the years ended December 31, 2007, 2006 and 2005, was $23.55, $25.22 and $18.36, per share, respectively. The grant-date fair value for the performance shares granted in 2007 and 2006 was determined by Monte Carlo simulation using a blended volatility term structure comprised of 50 percent historical volatility and 50 percent implied volatility and a risk-free interest rate term structure based on U.S. Treasury security rates in effect as of the grant date. In addition, the mean over all simulation paths of the discounted dividends expected to be earned in the performance period used in the valuation was $1.25 and $1.37 per target share for the 2007 and 2006 awards, respectively. The grant-date fair value for the performance shares issued in 2005 was equal to the market value of the common stock on the grant date. The fair value of performance share awards that vested during the years ended December 31, 2007 and 2006, was $6.0 million and $2.2 million, respectively.

A summary of the status of the performance share awards for the year ended December 31, 2007, was as follows:

	Number of Shares	Weighted Average Grant-Date Fair Value
Nonvested at beginning of period	738,684	$19.27
Granted	200,395	23.55
Vested	(228,452)	15.81
Forfeited	(86,128)	19.26
Nonvested at end of period	624,499	$21.91

NOTE 15 – INCOME TAXES
The components of income before income taxes for each of the years ended December 31 were as follows:

	2007	2006	2005
		(In thousands)	
United States	$ 508,210	$ 469,741	$ 397,703
Foreign	4,600	4,148	13,837
Income before income taxes	$ 512,810	$ 473,889	$ 411,540

Income tax expense for the years ended December 31 was as follows:

	2007	2006	2005
		(In thousands)	
Current:			
Federal	$ 106,399	$ 108,843	$ 102,736
State	15,135	18,487	20,449
Foreign	235	136	(93)
	121,769	127,466	123,092
Deferred:			
Income taxes –			
Federal	58,030	34,693	19,278
State	9,656	4,357	4,379
Investment tax credit	(414)	(405)	(500)
	67,272	38,645	23,157
Change in uncertain tax benefits	869	---	---
Change in accrued interest	114	---	---
Total income tax expense	$ 190,024	$ 166,111	$ 146,249

Components of deferred tax assets and deferred tax liabilities recognized at December 31 were as follows:

	2007	2006
	(In thousands)	
Deferred tax assets:		
Accrued pension costs	$ 44,002	$ 43,433
Regulatory matters	43,866	35,978
Asset retirement obligations	15,163	14,789
Deferred compensation	13,677	13,286
Other	45,335	43,818
Total deferred tax assets	162,043	151,304
Deferred tax liabilities:		
Depreciation and basis differences on property, plant and equipment	498,933	445,315
Basis differences on natural gas and oil producing properties	260,417	204,288
Regulatory matters	17,630	18,019
Natural gas and oil price swap and collar agreements	3,989	12,359
Other	42,044	23,894
Total deferred tax liabilities	823,013	703,875
Net deferred income tax liability	$ (660,970)	$ (552,571)

As of December 31, 2007 and 2006, no valuation allowance has been recorded associated with the above deferred tax assets.

The following table reconciles the change in the net deferred income tax liability from December 31, 2006, to December 31, 2007, to deferred income tax expense:

	2007 (In thousands)
Change in net deferred income tax liability from the preceding table	$ 108,399
Deferred taxes associated with other comprehensive loss	2,804
Deferred taxes associated with acquisitions	(46,229)
Other	2,298
Deferred income tax expense for the period	$ 67,272

Total income tax expense differs from the amount computed by applying the statutory federal income tax rate to income before taxes. The reasons for this difference were as follows:

Years ended December 31,	2007		2006		2005	
	Amount	%	Amount	%	Amount	%
	(Dollars in thousands)					
Computed tax at federal statutory rate	$179,484	35.0	$165,861	35.0	$144,039	35.0
Increases (reductions) resulting from:						
State income taxes, net of federal income tax benefit	17,121	3.3	17,786	3.8	15,064	3.7
Deferred taxes associated with unrepatriated foreign earnings	9,368	1.8	---	---	---	---
Domestic production activities deduction	(4,787)	(.9)	(2,324)	(.5)	(2,219)	(.5)
Depletion allowance	(4,073)	(.8)	(4,784)	(1.0)	(4,381)	(1.1)
Resolution of tax matters	208	---	(3,660)	(.8)	---	---
Foreign operations	235	---	136	---	(4,225)	(1.0)
Other items	(7,532)	(1.3)	(6,904)	(1.4)	(2,029)	(.6)
Total income tax expense	$190,024	37.1	$166,111	35.1	$146,249	35.5

Prior to the sale of the domestic independent power production assets on July 10, 2007, as discussed in Note 3, the Company considered earnings (including the gain from the sale of its foreign equity method investment in a natural gas-fired electric generating facility in Brazil in 2005) to be reinvested indefinitely outside of the United States and, accordingly, no U.S. deferred income taxes were recorded with respect to such earnings. Following the sale of these assets, the Company reconsidered its long-term plans for future development and expansion of its foreign investment and has determined that it has no immediate plans to explore or invest in additional foreign investments at this time. Therefore, in accordance with SFAS No. 109, in the third quarter of 2007, deferred income taxes were accrued with respect to the temporary differences which had not been previously recorded. The cumulative undistributed earnings at December 31, 2007, were approximately $36 million. The amount of deferred tax liability, net of allowable foreign tax credits, associated with the undistributed earnings and recognized during 2007 was approximately $9.4 million. Future earnings will also be subject to additional U.S. taxes, net of allowable foreign tax credits.

On January 1, 2007, the Company adopted FIN 48 as discussed in Note 1. The Company and its subsidiaries file income tax returns in the U.S. federal jurisdiction, and various state, local and foreign jurisdictions. With few exceptions, the Company is no longer subject to U.S. federal, state and local, or non-U.S. income tax examinations by tax authorities for years ending prior to 2004.

Upon the adoption of FIN 48, the Company recognized a decrease in the liability for unrecognized tax benefits, which was not material and was accounted for as an increase to the January 1, 2007, balance of retained earnings. At the date of adoption, the amount of unrecognized tax benefits was $4.5 million.

A reconciliation of the unrecognized tax benefits (excluding interest) for the year ended December 31, 2007, was as follows:

	2007
	(In thousands)
Balance at beginning of year	$ 4,241
Additions based on tax positions related to the current year	373
Additions for tax positions of prior years	588
Lapse of statute of limitations	(1,467)
Balance at end of year	$ 3,735

Included in the balance of unrecognized tax benefits at December 31, 2007, were $1.6 million of tax positions for which the ultimate deductibility is highly certain but for which there is uncertainty about the timing of such deductibility. Because of the impact of deferred tax accounting, other than interest and penalties, the disallowance of the shorter deductibility period would not affect the annual effective tax rate but would accelerate the payment of cash to the taxing authority to an earlier period. The amount of unrecognized tax benefits that, if recognized, would affect the effective tax rate at December 31, 2007, was $2.6 million, including approximately $441,000 for the payment of interest and penalties.

The Company does not anticipate the amount of unrecognized tax benefits to significantly increase or decrease within the next 12 months.

The Company recognizes interest and penalties accrued related to unrecognized tax benefits in income taxes. For the years ended December 31, 2007, 2006 and 2005, the Company recognized approximately $680,000, $7,100 and $7,300, respectively, in interest expense. Penalties were not material in 2007, 2006 and 2005. The Company recognized interest income of approximately $480,000, $1.5 million and $62,000 for the years ended December 31, 2007, 2006 and 2005, respectively. The Company had accrued liabilities of approximately $718,000 and $436,000 at December 31, 2007 and 2006, respectively, for the payment of interest.

NOTE 16 – BUSINESS SEGMENT DATA

The Company's reportable segments are those that are based on the Company's method of internal reporting, which generally segregates the strategic business units due to differences in products, services and regulation. The vast majority of the Company's operations are located within the United States. The Company also has investments in foreign countries, which largely consist of the Company’s equity method investment in the Brazilian Transmission Lines.

Prior to the fourth quarter of 2007, the Company reported seven business segments consisting of electric, natural gas distribution, construction services, pipeline and energy services, natural gas and oil production, construction materials and contracting, and independent power production. As discussed in Note 3, the domestic independent power production assets were sold in the third quarter of 2007, and as a result, the remaining independent power production operations are no longer significant and do not meet the criteria to be considered a reportable segment. Therefore, the remaining operations of the independent power production segment, including the Company's equity method investment in the Brazilian Transmission Lines, are reported in the Other category. The other operations do not meet the criteria to be considered a reportable segment. The Company's operations are now conducted through six reportable segments and prior period information has been restated to reflect this change.

The electric segment generates, transmits and distributes electricity in Montana, North Dakota, South Dakota and Wyoming. The natural gas distribution segment distributes natural gas in those states as well as in Minnesota, Oregon and Washington. These operations also supply related value-added products and services.

The construction services segment specializes in electric line construction, pipeline construction, utility excavation, inside electrical wiring, cabling and mechanical work, fire protection and the manufacture and distribution of specialty equipment.

The pipeline and energy services segment provides natural gas transportation, underground storage and gathering services through regulated and nonregulated pipeline systems primarily in the Rocky Mountain and northern Great Plains regions of the United States. The pipeline and energy services segment also provides energy-related management services.

The natural gas and oil production segment is engaged in natural gas and oil acquisition, exploration, development and production activities in the Rocky Mountain and Mid-Continent regions of the United States and in and around the Gulf of Mexico.

The construction materials and contracting segment mines aggregates and markets crushed stone, sand, gravel and related construction materials, including ready-mixed concrete, cement, asphalt, liquid asphalt and other value-added products. It also performs integrated construction services. The construction materials and contracting segment operates in the central, southern and western United States and Alaska and Hawaii.

The Other category includes the activities of Centennial Capital, which insures various types of risks as a captive insurer for certain of the Company's subsidiaries. The function of the captive insurer is to fund the deductible layers of the insured companies' general liability and automobile liability coverages. Centennial Capital also owns certain real and personal property. The Other category also includes the Company's equity investment in the Brazilian Transmission Lines.

The information below follows the same accounting policies as described in the Summary of Significant Accounting Policies. Information on the Company's businesses as of December 31 and for the years then ended was as follows:

	2007	2006	2005
		(In thousands)	
External operating revenues:			
Electric	$ 193,367	$ 187,301	$ 181,238
Natural gas distribution	532,997	351,988	384,199
Pipeline and energy services	369,345	349,997	384,887
	1,095,709	889,286	950,324
Construction services	1,102,566	987,079	686,734
Natural gas and oil production	288,148	251,153	163,539
Construction materials and contracting	1,761,473	1,877,021	1,603,326
Other	---	---	---
	3,152,187	3,115,253	2,453,599
Total external operating revenues	$ 4,247,896	$ 4,004,539	$ 3,403,923
Intersegment operating revenues:			
Electric	$ ---	$ ---	$ ---
Natural gas distribution	---	---	---
Construction services	649	503	391

Pipeline and energy services	77,718	93,723	92,424
Natural gas and oil production	226,706	232,799	275,828
Construction materials and contracting	---	---	1,284
Other	10,061	8,117	6,038
Intersegment eliminations	(315,134)	(335,142)	(375,965)
Total intersegment operating revenues	$ ---	$ ---	$ ---
Depreciation, depletion and amortization:			
Electric	$ 22,549	$ 21,396	$ 20,818
Natural gas distribution	19,054	9,776	9,534
Construction services	14,314	15,449	13,459
Pipeline and energy services	21,631	13,288	12,513
Natural gas and oil production	127,408	106,768	84,754
Construction materials and contracting	95,732	88,723	77,988
Other	1,244	1,131	374
Total depreciation, depletion and amortization	$ 301,932	$ 256,531	$ 219,440
Interest expense:			
Electric	$ 6,737	$ 6,493	$ 7,553
Natural gas distribution	13,566	3,885	3,973
Construction services	4,878	6,295	4,177
Pipeline and energy services	8,769	8,094	8,132
Natural gas and oil production	8,394	9,864	7,550
Construction materials and contracting	23,997	25,943	21,365
Other	10,717	11,775	1,861
Intersegment eliminations	(4,821)	(254)	(227)
Total interest expense	$ 72,237	$ 72,095	$ 54,384
Income taxes:			
Electric	$ 8,528	$ 7,403	$ 8,308
Natural gas distribution	6,477	2,108	2,240
Construction services	26,829	16,497	9,693
Pipeline and energy services	18,524	18,938	13,735
Natural gas and oil production	78,348	78,960	82,428
Construction materials and contracting	39,045	46,245	29,244
Other	12,273	(4,040)	601
Total income taxes	$ 190,024	$ 166,111	$ 146,249
Earnings on common stock:			
Electric	$ 17,700	$ 14,401	$ 13,940
Natural gas distribution	14,044	5,680	3,515
Construction services	43,843	27,851	14,558
Pipeline and energy services	31,408	32,126	22,867
Natural gas and oil production	142,485	145,657	141,625

Construction materials and contracting	77,001	85,702	55,040
Other	(4,380)	(4,324)	13,061
Earnings on common stock before income from discontinued operations	322,101	307,093	264,606
Income from discontinued operations, net of tax	109,334	7,979	9,792
Total earnings on common stock	$ 431,435	$ 315,072	$ 274,398
Capital expenditures:			
Electric	$ 91,548	$ 39,055	$ 27,036
Natural gas distribution	500,178	15,398	17,224
Construction services	18,241	31,354	50,900
Pipeline and energy services	39,162	42,749	36,318
Natural gas and oil production	283,589	328,979	329,773
Construction materials and contracting	189,727	141,088	161,977
Other	1,621	2,052	14,722
Net proceeds from sale or disposition of property	(24,983)	(30,501)	(40,460)
Net capital expenditures before discontinued operations	1,099,083	570,174	597,490
Discontinued operations	(548,216)	33,090	132,956
Total net capital expenditures	$ 550,867	$ 603,264	$ 730,446
Assets:			
Electric*	$ 428,200	$ 353,593	$ 330,327
Natural gas distribution*	942,454	264,102	271,653
Construction services	456,564	401,832	351,654
Pipeline and energy services	500,755	474,424	466,961
Natural gas and oil production	1,299,406	1,173,797	898,883
Construction materials and contracting	1,642,729	1,562,868	1,498,338
Other**	322,326	672,858	605,746
Total assets	$ 5,592,434	$ 4,903,474	$ 4,423,562
Property, plant and equipment:			
Electric*	$ 784,705	$ 703,838	$ 670,771
Natural gas distribution*	948,446	289,106	277,288
Construction services	101,935	94,754	90,110
Pipeline and energy services	600,712	562,596	521,495
Natural gas and oil production	1,923,899	1,636,245	1,303,447
Construction materials and contracting	1,538,716	1,410,657	1,310,426
Other	31,833	30,529	28,467
Less accumulated depreciation, depletion and amortization	2,270,691	1,735,302	1,523,887
Net property, plant and equipment	$ 3,659,555	$ 2,992,423	$ 2,678,117

* Includes allocations of common utility property.

**

Includes the domestic independent power production assets in 2006 and 2005 that were sold in 2007, and assets not directly assignable to a business (i.e. cash and cash equivalents, certain accounts receivable, certain investments and other miscellaneous current and deferred assets).

The pipeline and energy services segment recognized income from discontinued operations, net of tax, of $106,000 for the year ended December 31, 2007, and a loss from discontinued operations, net of tax, of $2.1 million and $775,000 for the years ended December 31, 2006 and 2005, respectively. The Other category reflects income from discontinued operations, net of tax, of $109.2 million, $10.1 million and $10.6 million for the years ended December 31, 2007, 2006 and 2005, respectively.

Excluding income (loss) from discontinued operations at pipeline and energy services, earnings from electric, natural gas distribution and pipeline and energy services are substantially all from regulated operations. Earnings from construction services, natural gas and oil production, construction materials and contracting, and other are all from nonregulated operations.

Capital expenditures for 2007, 2006 and 2005 include noncash transactions, including the issuance of the Company's equity securities in connection with acquisitions and the outstanding indebtedness related to the 2007 Cascade acquisition. The noncash transactions were $217.3 million in 2007, immaterial in 2006 and $46.5 million in 2005.

NOTE 17 – EMPLOYEE BENEFIT PLANS

The Company has noncontributory defined benefit pension plans and other postretirement benefit plans for certain eligible employees. Effective January 1, 2006, the Company discontinued defined pension plan benefits to all nonunion and certain union employees hired after December 31, 2005. These employees that would have been eligible for defined pension plan benefits are eligible to receive additional defined contribution plan benefits. The Company uses a measurement date of December 31 for all of its pension and postretirement benefit plans.

Changes in benefit obligation and plan assets for the year ended December 31, 2007, and amounts recognized in the Consolidated Balance Sheets at December 31, 2007, were as follows:

	Pension Benefits		Other Postretirement Benefits	
	2007	2006	2007	2006
	(In thousands)			
Change in benefit obligation:				
Benefit obligation at beginning of year	$ 298,398	$ 303,393	$ 67,724	$ 69,811
Service cost	9,098	8,901	1,865	2,015
Interest cost	18,591	16,056	4,212	3,633
Plan participants' contributions	---	---	1,790	1,533
Actuarial (gain) loss	(8,079)	(14,363)	482	(4,019)
Acquisition	63,556	---	11,734	---
Benefits paid	(21,641)	(15,589)	(6,226)	(5,249)
Benefit obligation at end of year	359,923	298,398	81,581	67,724
Change in plan assets:				
Fair value of plan assets at beginning of year	259,275	245,328	58,747	52,448
Actual gain on plan assets	28,393	27,047	2,357	6,440
Employer contribution	4,236	2,489	3,888	3,575
Plan participants' contributions	---	---	1,790	1,533
Acquisition	60,703	---	13,128	---
Benefits paid	(21,641)	(15,589)	(6,226)	(5,249)

Fair value of plan assets at end of year	330,966	259,275	73,684	58,747
Funded status – under	$ (28,957)	$ (39,123)	$ (7,897)	$ (8,977)
Amounts recognized in the Consolidated Balance Sheets at December 31:				
Prepaid benefit cost (noncurrent)	$ 10,253	$ 4,368	$ 664	$ ---
Accrued benefit liability (current)	---	---	(408)	(364)
Accrued benefit liability (noncurrent)	(39,210)	(43,491)	(8,153)	(8,613)
Net amount recognized	$ (28,957)	$ (39,123)	$ (7,897)	$ (8,977)
Amounts recognized in accumulated other comprehensive loss consist of:				
Actuarial (gain) loss	$ 30,006	$ 30,415	$ (2,466)	$ (13,718)
Prior service cost (credit)	3,350	5,948	(10,524)	648
Transition obligation	---	---	10,628	12,753
Total	$ 33,356	$ 36,363	$ (2,362)	$ (317)

Employer contributions and benefits paid in the above table include only those amounts contributed directly to, or paid directly from, plan assets.

Unrecognized pension actuarial losses in excess of 10 percent of the greater of the projected benefit obligation or the market-related value of assets is amortized on a straight-line basis over the expected average remaining service lives of active participants. The market-related value of assets is determined using a five-year average of assets. Unrecognized postretirement net transition obligation is amortized over a 20-year period ending 2012.

The accumulated benefit obligation for the defined benefit pension plans reflected above was $307.7 million and $245.6 million at December 31, 2007 and 2006, respectively.

The projected benefit obligation, accumulated benefit obligation and fair value of plan assets for the pension plans with accumulated benefit obligations in excess of plan assets at December 31, 2007 and 2006, were as follows:

	2007	2006
	(In thousands)	
Projected benefit obligation	$ 106,236	$ 187,638
Accumulated benefit obligation	$ 95,435	$ 151,850
Fair value of plan assets	$ 94,845	$ 148,261

Components of net periodic benefit cost for the Company's pension and other postretirement benefit plans for the years ended December 31, 2007 and 2006, were as follows:

	Pension Benefits		Other Postretirement Benefits	
	2007	2006	2007	2006
			(In thousands)	
Components of net periodic benefit cost:				
Service cost	$ 9,098	$ 8,901	$ 1,865	$ 2,015
Interest cost	18,591	16,056	4,212	3,633
Expected return on assets	(22,524)	(19,913)	(4,776)	(4,119)
Amortization of prior service cost (credit)	756	913	(1,300)	46
Recognized net actuarial (gain) loss	1,605	1,699	73	(243)
Amortization of net transition obligation (asset)	---	(3)	2,125	2,125
Net periodic benefit cost, including amount capitalized	7,526	7,653	2,199	3,457
Less amount capitalized	991	689	373	261

Net periodic benefit cost	6,535	6,964	1,826	3,196
Other changes in plan assets and benefit obligations recognized in accumulated other comprehensive loss:				
Net (gain) loss	(11,095)	(22,983)	1,507	(6,340)
Acquisition-related actuarial loss	12,291	---	9,818	---
Acquisition-related prior service credit	(1,842)	---	(12,472)	---
Amortization of actuarial gain (loss)	(1,605)	(1,699)	(73)	243
Amortization of prior service cost (credit)	(756)	(913)	1,300	(46)
Amortization of net transition (obligation) asset	---	3	(2,125)	(2,125)
Total recognized in accumulated other comprehensive loss	(3,007)	(25,592)	(2,045)	(8,268)
Total recognized in net periodic benefit cost and accumulated other comprehensive loss	$ 3,528	$ (18,628)	$ (219)	$ (5,072)

Components of net periodic benefit cost for the Company's pension and other postretirement benefit plans for the year ended December 31, 2005, was as follows:

	Pension Benefits 2005	Other Postretirement Benefits 2005
	(In thousands)	
Components of net periodic benefit cost:		
Service cost	$ 8,336	$ 1,719
Interest cost	16,617	3,784
Expected return on assets	(19,947)	(4,005)
Amortization of prior service cost	1,025	45
Recognized net actuarial (gain) loss	1,385	(549)
Amortization of net transition obligation (asset)	(45)	2,126
Net periodic benefit cost, including amount capitalized	7,371	3,120
Less amount capitalized	730	313
Net periodic benefit cost	$ 6,641	$ 2,807

The estimated net loss and prior service cost for the defined benefit pension plans that will be amortized from accumulated other comprehensive loss into net periodic benefit cost in 2008 are $967,000 and $665,000, respectively. The estimated net loss, prior service credit and transition obligation for the other postretirement benefit plans that will be amortized from accumulated other comprehensive loss into net periodic benefit cost in 2008 are $461,000, $2.8 million and $2.1 million, respectively.

Weighted average assumptions used to determine benefit obligations at December 31 were as follows:

	Pension Benefits		Other Postretirement Benefits	
	2007	2006	2007	2006
Discount rate	6.00%	5.75%	6.00%	5.75%
Rate of compensation increase	4.20%	4.30%	4.50%	4.50%

Weighted average assumptions used to determine net periodic benefit cost for the years ended December 31 were as follows:

Other

	Pension Benefits 2007	Pension Benefits 2006	Postretirement Benefits 2007	Postretirement Benefits 2006
Discount rate	5.75%	5.50%	5.75%	5.50%
Expected return on plan assets	8.40%	8.50%	7.50%	7.50%
Rate of compensation increase	4.20%	4.30%	4.50%	4.50%

The expected rate of return on plan assets is based on the targeted asset allocation of 70 percent equity securities and 30 percent fixed-income securities and the expected rate of return from these asset categories. The expected return on plan assets for other postretirement benefits reflects insurance-related investment costs.

Health care rate assumptions for the Company's other postretirement benefit plans as of December 31 were as follows:

	2007	2006
Health care trend rate assumed for next year	6.0%-10.0%	6.0%-9.0%
Health care cost trend rate – ultimate	5.0%-6.0%	5.0%-6.0%
Year in which ultimate trend rate achieved	1999-2017	1999-2014

The Company's other postretirement benefit plans include health care and life insurance benefits for certain employees. The plans underlying these benefits may require contributions by the employee depending on such employee's age and years of service at retirement or the date of retirement. The accounting for the health care plans anticipates future cost-sharing changes that are consistent with the Company's expressed intent to generally increase retiree contributions each year by the excess of the expected health care cost trend rate over 6 percent.

Assumed health care cost trend rates may have a significant effect on the amounts reported for the health care plans. A one percentage point change in the assumed health care cost trend rates would have had the following effects at December 31, 2007:

	1 Percentage Point Increase	1 Percentage Point Decrease
	(In thousands)	
Effect on total of service and interest cost components	$(21)	$(930)
Effect on postretirement benefit obligation	$1,335	$(9,796)

The Company's defined benefit pension plans' asset allocation at December 31, 2007 and 2006, and weighted average targeted asset allocations at December 31, 2007, were as follows:

Asset Category	Percentage of Plan Assets 2007	Percentage of Plan Assets 2006	Weighted Average Targeted Asset Allocation Percentage 2007
Equity securities	66%	69%	70%
Fixed-income securities	29	27	30*
Other	5	4	---
Total	100%	100%	100%

* Includes target for both fixed-income securities and other.

The Company's pension assets are managed by 12 outside investment managers. The Company's other postretirement assets are managed by three outside investment managers. The Company's investment policy with respect to pension and other postretirement assets is to make investments solely in the interest of the participants and beneficiaries of the plans and for the exclusive purpose of providing benefits accrued and defraying the reasonable expenses of administration. The Company strives to maintain investment diversification to assist in minimizing the risk of large losses. The Company's policy guidelines allow for investment of funds in cash equivalents, fixed-income securities and equity securities. The guidelines prohibit investment in commodities and future contracts, equity private placement, employer securities, leveraged or derivative securities, options, direct real estate investments, precious metals, venture capital and limited partnerships. The guidelines also prohibit short selling and margin transactions. The Company's practice is to periodically review and rebalance asset categories based on its targeted asset allocation percentage policy.

The Company's other postretirement benefit plans' asset allocation at December 31, 2007 and 2006, and weighted average targeted asset allocation at December 31, 2007, were as follows:

	Percentage of Plan Assets		Weighted Average Targeted Asset Allocation Percentage
Asset Category	2007	2006	2007
Equity securities	70%	70%	70%
Fixed-income securities	27	27	30*
Other	3	3	---
Total	100%	100%	100%

* Includes target for both fixed-income securities and other.

The Company expects to contribute approximately $5.6 million to its defined benefit pension plans and approximately $3.5 million to its postretirement benefit plans in 2008.

The following benefit payments, which reflect future service, as appropriate, are expected to be paid:

Years	Pension Benefits	Other Postretirement Benefits
	(In thousands)	
2008	$ 18,199	$ 5,229
2009	18,993	5,429
2010	20,144	5,630
2011	21,046	5,852
2012	22,388	6,067
2013-2017	130,377	33,643

The following Medicare Part D subsidies are expected: $736,000 in 2008; $786,000 in 2009; $841,000 in 2010; $889,000 in 2011; $948,000 in 2012; and $5.6 million during the years 2013 through 2017.

In addition to company-sponsored plans, certain employees are covered under multi-employer pension plans administered by a union. Amounts contributed to the multi-employer plans were $51.5 million, $57.6 million and

$39.6 million in 2007, 2006 and 2005, respectively.

In addition to the qualified plan defined pension benefits reflected in the table at the beginning of this note, the Company also has an unfunded, nonqualified benefit plan for executive officers and certain key management employees that generally provides for defined benefit payments at age 65 following the employee's retirement or to their beneficiaries upon death for a 15-year period. The Company had investments of $55.0 million at December 31, 2007, consisting of equity securities of $26.4 million, life insurance carried on plan participants (payable upon the employee's death) of $20.8 million, fixed-income securities of $4.0 million, and other investments of $3.8 million, which the Company anticipates using to satisfy obligations under this plan. The Company's net periodic benefit cost for this plan was $7.6 million, $7.5 million and $7.4 million in 2007, 2006 and 2005, respectively. The total projected benefit obligation for this plan was $80.6 million and $69.5 million at December 31, 2007 and 2006, respectively. The accumulated benefit obligation for this plan was $69.3 million and $57.4 million at December 31, 2007 and 2006, respectively. A discount rate of 6.00 percent and 5.75 percent at December 31, 2007 and 2006, respectively, and a rate of compensation increase of 4.25 percent at December 31, 2007 and 2006, were used to determine benefit obligations. A discount rate of 5.75 percent and 5.50 percent at December 31, 2007 and 2006, respectively, and a rate of compensation increase of 4.25 percent at December 31, 2007 and 2006, were used to determine net periodic benefit cost.

The amount of benefit payments for the unfunded, nonqualified benefit plan, as appropriate, are expected to aggregate $3.5 million in 2008; $3.6 million in 2009; $4.1 million in 2010; $4.4 million in 2011; $4.8 million in 2012; and $31.1 million for the years 2013 through 2017.

The Company sponsors various defined contribution plans for eligible employees. Costs incurred by the Company under these plans were $21.1 million in 2007, $17.3 million in 2006 and $17.0 million in 2005. The costs incurred in each year reflect additional participants as a result of business acquisitions.

SFAS No. 158 became effective for the Company as of December 31, 2006. The adoption resulted in a negative transition effect on accumulated other comprehensive loss of $18.5 million.

NOTE 18 – JOINTLY OWNED FACILITIES

The consolidated financial statements include the Company's 22.7 percent and 25.0 percent ownership interests in the assets, liabilities and expenses of the Big Stone Station and the Coyote Station, respectively. Each owner of the Big Stone and Coyote stations is responsible for financing its investment in the jointly owned facilities.

The Company's share of the Big Stone Station and Coyote Station operating expenses was reflected in the appropriate categories of operating expenses in the Consolidated Statements of Income.

At December 31, the Company's share of the cost of utility plant in service and related accumulated depreciation for the stations was as follows:

	2007	2006
	(In thousands)	
Big Stone Station:		
Utility plant in service	$ 61,568	$ 55,659
Less accumulated depreciation	39,168	38,881
	$ 22,400	$ 16,778
Coyote Station:		
Utility plant in service	$ 125,826	$ 125,950
Less accumulated depreciation	79,783	78,056
	$ 46,043	$ 47,894

NOTE 19 – REGULATORY MATTERS AND REVENUES SUBJECT TO REFUND

In August 2006, CMS, a competing gas marketer, filed a complaint against Cascade before the WUTC alleging Cascade had entered into gas supply sales contracts with its non-core, transportation-only customers in violation of state law by not filing tariffs and copies of the gas supply contracts with the WUTC. CMS's complaint additionally raised claims of undue preference and discrimination. On January 12, 2007, the WUTC entered an order allowing Cascade to continue to make gas supply sales to non-core, transportation-only customers but requiring Cascade to file its tariffs and sales contracts with the WUTC. On February 12, 2007, Cascade filed revisions to its tariffs reflecting gas supply service options available to non-core, transportation-only customers; however, on March 14, 2007, the WUTC suspended the tariff filing. On March 30, 2007, due to the lack of approved tariffs, Cascade filed notice with the WUTC that it was reactivating a nonregulated affiliate to make retail gas sales to non-core, transportation-only customers. The WUTC consolidated the tariff proceeding with Cascade's filing to re-establish an affiliate to make non-core, transportation-only customer gas supply sales. On December 7, 2007, the WUTC filed a complaint against Cascade alleging it is in violation of its most recent general rate case settlement by not sharing gas supply sales margins with core customers. Cascade filed an answer to the complaint on December 27, 2007. On February 6, 2008, Cascade and the other participant parties entered into an agreement settling the issues in all of the above proceedings. Under the settlement, Cascade and its subsidiaries will discontinue the unbundled retail sale of gas supply to non-core, transportation-only customers by November 1, 2008. Fifty percent of the net gas supply sales margins realized from non-core, transportation-only customers by Cascade and its subsidiaries from April 1, 2007, through October 31, 2008, and fifty percent of the net gain, if any, from the sale of such business, will be credited to Cascade’s core customers. Cascade will also revise its gas procurement strategy for core customers to enhance its ability to acquire gas supply from the Rocky Mountain region. The settlement is subject to approval by the WUTC. Cascade has reserved an amount for the crediting of the net gas supply sales margins generated from April 1, 2007, through December 31, 2007. Cascade does not consider the discontinuance of gas supply sales to non-core, transportation-only customers to have a material impact on its financial position or results of operations.

On July 12, 2007, Montana-Dakota filed an application with the MTPSC for an electric rate increase. Montana-Dakota requested a total of $7.8 million annually or approximately 22 percent above current rates. Montana-Dakota requested a fuel and purchased power tracking adjustment and an off-system sales margin sharing adjustment. Montana-Dakota also requested an interim increase of $3.9 million annually, subject to refund. On December 5, 2007, the MTPSC granted an interim increase of $3.4 million annually. On February 8, 2008, Montana-Dakota and the interveners reached a settlement stipulation (subject to MTPSC approval) applicable to this filing whereby the $3.4 million of interim rate relief will become final upon approval of the stipulation and an additional annual rate increase of $730,000 will become effective January 1, 2009. As part of the settlement, Montana-Dakota will be allowed to implement a fuel and purchased power tracking mechanism on a shared basis, a margin sharing mechanism for off-system sales, and modify certain decommissioning and net negative salvage cost accruals. Also, Montana-Dakota will agree to not implement new rates from any subsequent general rate filings before January 1, 2010.

In November 2006, Montana-Dakota filed an application with the NDPSC requesting an advance determination of prudence of Montana-Dakota's ownership interest in Big Stone Station II, which is expected to be completed in 2013. Hearings on the application were held in June 2007. In September 2007, Montana-Dakota informed the NDPSC that certain of the other participants in the project had withdrawn, that it was considering the impact of these withdrawals on the project and its options, and proposed that the NDPSC suspend the procedural schedule. In October 2007, Montana-Dakota proposed to supplement the record with additional resource planning analysis reflecting changes in plant configuration as a result of the participant withdrawals. On February 1, 2008, the NDPSC issued an order setting supplemental hearings to commence April 28, 2008. The MNPUC is expected to rule on the issuance of the related transmission Certificate of Need in April 2008 and the NDPSC is expected to rule on the advance determination of prudence in June 2008.

In December 1999, Williston Basin filed a general natural gas rate change application with the FERC. Williston Basin began collecting such rates effective June 1, 2000, subject to refund. Currently, the only remaining issue outstanding related to this rate change application is in regard to certain service restrictions. In May 2004, the FERC remanded this issue to an ALJ for resolution. In November 2005, the FERC issued an Order on Initial Decision affirming the ALJ's Initial Decision regarding certain service and annual demand quantity restrictions. In April 2006, the FERC issued an Order on Rehearing denying Williston Basin's Request for Rehearing of the FERC's Order on Initial Decision. In April 2006, Williston Basin appealed to the D.C. Appeals Court certain issues addressed by the FERC's Order on Initial Decision and its Order on Rehearing. The matter concerning the service restrictions is pending resolution by the D.C. Appeals Court.

NOTE 20 – COMMITMENTS AND CONTINGENCIES

Litigation

Coalbed Natural Gas Operations Fidelity has been named as a defendant in, and/or certain of its operations are or have been the subject of, more than a dozen lawsuits filed in connection with its CBNG development in the Powder River Basin in Montana and Wyoming. These lawsuits were filed in federal and state courts in Montana between June 2000 and January 2007 by a number of environmental organizations, including the NPRC and the Montana Environmental Information Center, as well as the TRWUA and the Northern Cheyenne Tribe. Portions of three of the lawsuits have been transferred to the Wyoming Federal District Court. The lawsuits involve allegations that Fidelity and/or various government agencies are in violation of state and/or federal law, including the Clean Water Act, the NEPA, the Federal Land Management Policy Act, the NHPA, the Montana State Constitution, the Montana Environmental Policy Act and the Montana Water Quality Act. The suits that remain extant include a variety of claims that state and federal government agencies violated various environmental laws that impose procedural and substantive requirements. The lawsuits seek injunctive relief, invalidation of various permits and unspecified damages. In addition, Fidelity has intervened or moved to intervene in three lawsuits filed by other gas producers between June and September 2006 that challenge rules adopted by the BER related to management of water associated with CBNG production. The state of Wyoming has filed a similar suit in September 2006 and Fidelity moved to intervene in that action. Fidelity is partly funding the Petroleum Association of Wyoming’s intervention in two suits. The first was brought by two landowners against the Wyoming State Engineer and the Wyoming Board of Control challenging the state’s CBNG groundwater permitting practices. The second suit was brought by the Wyoming Outdoor Council and Powder River Basin Resource Council appealing the Wyoming Environmental Quality Council’s rules establishing water quality standards relating to discharges of water associated with CBNG production.

In suits filed in the Montana Federal District Court, the NPRC and the Northern Cheyenne Tribe asserted that the BLM violated NEPA and other federal laws when approving the 2003 EIS analyzing CBNG development in southeastern Montana. The Montana Federal District Court, in February 2005, entered a ruling finding that the 2003 EIS was inadequate. The Montana Federal District Court later entered an order that would have allowed limited CBNG development in the Montana Powder River Basin pending the BLM's preparation of a SEIS. The plaintiffs appealed the decision to the Ninth Circuit because the Montana Federal District Court declined to enter an injunction enjoining all development pending completion of the SEIS. The Montana Federal District Court also declined to enter an injunction pending the appeal. In May 2005, the Ninth Circuit granted the request of the NPRC and the Northern Cheyenne Tribe and, pending appeal or further order from the Ninth Circuit, enjoined the BLM from approving any new CBNG development on federal lands in the Montana Powder River Basin. The Ninth Circuit also enjoined Fidelity from drilling any additional federally permitted wells associated with its Montana Coal Creek Project and from constructing infrastructure to produce and transport CBNG from the Coal Creek Project's existing federal wells. The matter was briefed and argued to the Ninth Circuit in September 2005. On September 11, 2007, the Ninth Circuit affirmed the Montana Federal District Court and ruled it had correctly issued an injunction allowing up to 500 CBNG wells to be drilled each year on private, state and federal land in the Montana Powder River Basin. On October 29, 2007, in response to a motion filed by Fidelity, the Ninth Circuit lifted the 2005 injunction it had earlier issued pending the appeal. On the same date, the Ninth Circuit ordered Fidelity to respond within 21 days to the Northern Cheyenne Tribe and the NPRC’s October 16, 2007, petition to the Ninth Circuit to rehear the case. On January 15, 2008, the Ninth Circuit denied the petition for rehearing.

In December 2006, the BLM issued a draft SEIS that endorses a phased-development approach to CBNG production in the Montana Powder River Basin, whereby future projects would be reviewed against four screens or filters (relating to water quality, wildlife, Native American concerns and air quality). Fidelity filed written comments on the draft SEIS asking the BLM to reconsider its proposed phased-development approach and to make numerous other changes to the draft SEIS. The public comment period on the draft SEIS concluded on May 2, 2007. In response to comments, the BLM published an Air Quality Supplement to the draft SEIS with the public comment period ending March 13, 2008. The final SEIS is scheduled for release in July 2008 with a Record of Decision expected in December 2008. Fidelity cannot predict what the final terms of the SEIS will be.

In related actions in the Montana Federal District Court, the NPRC and the Northern Cheyenne Tribe asserted, among other things, that the actions of the BLM in approving Fidelity's applications for permits and the plan of development for the Badger Hills Project in Montana did not comply with applicable federal laws, including the NHPA and the NEPA. In June 2005, the Montana Federal District Court issued orders in these cases enjoining operations on Fidelity's Badger Hills Project pending the BLM's consultation with the Northern Cheyenne Tribe as to satisfaction of the applicable requirements of the NHPA and a further environmental analysis under the NEPA. Fidelity sought and obtained stays of the injunctive relief from the Montana Federal District Court and production from Fidelity’s Badger Hills Project continues. In September 2005, the Montana Federal District Court entered an Order based on a stipulation between the parties to the NPRC action that production from existing wells in Fidelity’s Badger Hills Project may continue pending preparation of a revised environmental analysis. In November 2005, the Montana Federal District Court entered an Order dismissing the Northern Cheyenne Tribe lawsuit based on the parties’ stipulation that production from existing wells in Fidelity’s Badger Hills Project could continue pending consultation with the Northern Cheyenne Tribe under the NHPA. In December 2005, Fidelity filed a Notice of Appeal of the NPRC lawsuit to the Ninth Circuit in connection with the Montana Federal District Court’s decision insofar as it found the BLM’s approval of Fidelity’s applications did not comply with applicable law.

In May 2005, the NPRC and other petitioners filed a petition with the BER to promulgate rules related to the management of water produced in association with CBNG operations. Thereafter, the BER initiated related rulemaking proceedings to consider rules that would, if promulgated, require re-injection of water produced in connection with CBNG operations, treatment of such water in the event re-injection is not feasible and amend the non-degradation policy in connection with CBNG development to include additional limitations on factors deemed harmful, thereby restricting discharges even further than under the previous standards. In March 2006, the BER issued its decision on the rulemaking petition. The BER rejected the proposed requirement of re-injection of water produced in connection with CBNG and deferred action on the proposed treatment requirement. The BER adopted the proposed amendment to the non-degradation policy. While it is possible the BER’s ruling could have an adverse impact on Fidelity’s operations, Fidelity believes that two five-year water discharge permits issued by the Montana DEQ in February 2006 should, assuming normal operating conditions, allow Fidelity to continue its existing CBNG operations at least through the expiration of the permits in March 2011. However, these permits are now under challenge in Montana state court by the Northern Cheyenne Tribe. Specifically, in April 2006, the Northern Cheyenne Tribe filed a complaint in the District Court of Big Horn County against the Montana DEQ seeking to set aside the two permits. The Northern Cheyenne Tribe asserted the Montana DEQ issued the permits in violation of various federal and state environmental laws. In particular, the Northern Cheyenne Tribe claimed the agency violated the Clean Water Act and the Montana Water Quality Act by failing to include in the permits conditions requiring application of the best practicable control technology currently available and by failing to impose a non-degradation policy like the one the BER adopted soon after the permit was issued. In addition, the Northern Cheyenne Tribe claimed that the actions of the Montana DEQ violated the Montana State Constitution’s guarantee of a clean and healthful environment, that the Montana DEQ’s related environmental assessment was invalid, that the Montana DEQ was required, but failed, to prepare an EIS and that the Montana DEQ failed to consider other alternatives to the issuance of the permits. Fidelity, the NPRC and the TRWUA have been granted leave to intervene in this proceeding. The parties have submitted cross motions for summary judgment. The motions were argued to the District Court of Big Horn County on February 28, 2007. Fidelity’s discharge of water pursuant to its two permits is its primary means for managing CBNG produced water. If its permits are set aside, Fidelity’s CBNG operations in Montana could be significantly and adversely affected.

In a related proceeding, in July 2006, Fidelity filed a motion to intervene in a lawsuit filed in the District Court of Big Horn County by other producers. The lawsuit challenges the BER's 2006 rulemaking, which amended the non-degradation policy, as well as the BER's 2003 rulemaking procedure which first set numeric limits for certain parameters contained in water produced in connection with CBNG operations. Fidelity's motion for intervention was granted in August 2006. The parties have briefed cross motions for summary judgment and the District Court of Big Horn County heard oral argument on those motions on July 2, 2007. On October 17, 2007, the District Court of Big Horn County entered an order granting the motions filed by the BER and others and denying the motions filed by Fidelity and other producers. The other producers appealed the order on December 26, 2007. Fidelity is not participating in the appeal.

Similarly, industry members have filed two lawsuits, and the state of Wyoming has filed one lawsuit, in Wyoming Federal District Court. These lawsuits challenge the EPA's failure to timely disapprove the 2006 rules. All three Wyoming lawsuits were consolidated in September 2006. Fidelity has moved to intervene in these consolidated cases.

Fidelity has also intervened in a Wyoming State District Court case in support of the Governor of Wyoming's decision not to promulgate rules which were proposed by the Powder River Basin Resource Council that would have granted Wyoming's DEQ authority to regulate water quantity issues that are currently regulated by the Wyoming State Engineer. In November 2007, the Wyoming State District Court dismissed the suit. The Powder River Basin Resource Council did not appeal.

Fidelity is partly funding the Petroleum Association of Wyoming's intervention in two suits. In the first case, in which the Petroleum Association of Wyoming's motion to intervene has been conditionally granted, the Powder River Basin Resource Council is funding litigation on behalf of two surface owners against the Wyoming State Engineer and the Wyoming Board of Control. The plaintiffs in the action, filed in Wyoming State District Court on June 14, 2007, seek a declaratory judgment that current ground water permitting practices are unlawful; that would mandate that the state adopt rules and procedures to ensure that coalbed groundwater is managed in accordance with the Wyoming Constitution and other laws; and that would prohibit the Wyoming State Engineer from issuing permits to produce coalbed groundwater and permits to store coalbed groundwater in reservoirs until the Wyoming State Engineer adopts such rules. In the second case, the Wyoming Outdoor Council and Powder River Basin Resource Council filed a petition on May 25, 2007, in the Wyoming State District Court seeking to invalidate the Environmental Quality Council's approval of amendments to Chapter 1 of the Wyoming Water Quality Rules and Regulations that subject certain discharges of water produced in connection with CBNG development to stricter water quality standards. The plaintiffs contend that the Wyoming DEQ's actions were arbitrary and capricious and that the rules are not in accordance with the Clean Water Act.

Fidelity will continue to vigorously defend its interests in all CBNG-related lawsuits and related actions in which it is involved, including the proceedings challenging its water permits. In those cases where damage claims have been asserted, Fidelity is unable to quantify the damages sought and will be unable to do so until after the completion of discovery. If the plaintiffs are successful in these lawsuits, the ultimate outcome of the actions could have a material adverse effect on Fidelity's existing CBNG operations and/or the future development of this resource in the affected regions.

Electric Operations Montana-Dakota joined with two electric generators in appealing a September 2003 finding by the ND Health Department that it may unilaterally revise operating permits previously issued to electric generating plants. Although it is doubtful that any revision of Montana-Dakota's operating permits by the ND Health Department would reduce the amount of electricity its plants could generate, the finding, if allowed to stand, could increase costs for sulfur dioxide removal and/or limit Montana-Dakota's ability to modify or expand operations at its North Dakota generation sites. Montana-Dakota and the other electric generators filed their appeal of the order in October 2003 in the Burleigh County District Court in Bismarck, North Dakota. Proceedings were stayed pending conclusion of the periodic review of sulfur dioxide emissions in the state.

In September 2005, the ND Health Department issued its final periodic review decision based on its August 2005 final air quality modeling report. The ND Health Department concluded there were no violations of the sulfur dioxide increment in North Dakota. In March 2006, the DRC filed a complaint in Colorado Federal District Court seeking to force the EPA to declare that the increment had been violated based on earlier modeling conducted by the EPA. The EPA defended against the DRC claim and filed a motion to dismiss the case. The Colorado Federal District Court has dismissed the case.

On June 6, 2007, the EPA noticed for public comment a proposed rule that would, among other things, adopt PSD increment modeling refinements that, if adopted, would operate to formally ratify the modeling techniques and conclusions contained in the September 2005 ND Health Department decision and the August 2005 final report. The public comment period on the proposed rule closed September 28, 2007. The dismissal of the case in Burleigh County District Court referenced above is dependant upon the outcome of the proposed rule.

In November 2006, the Sierra Club sent a notice of intent to file a citizen suit in federal court under the Clean Air Act to the co-owners, including Montana-Dakota, of the Big Stone Station. The suit would seek injunctive relief and monetary penalties based on the Sierra Club’s claim that three projects conducted at the Big Stone Station between 1995 and 2005 were modifications of a major source and that the Big Stone Station failed to obtain a PSD permit, conduct best available control technology analyses, and comply with other regulatory requirements for those projects. The South Dakota Department of Environment and Natural Resources reviewed and approved the three projects and the co-owners of the Big Stone Station believe the Sierra Club’s claims are without merit. The Big Stone Station co-owners intend to vigorously defend their interests if the suit is filed.

Natural Gas Storage Based on reservoir and well pressure data and other information, Williston Basin believes that reservoir pressure (and therefore the amount of gas) in the EBSR, one of its natural gas storage reservoirs, has decreased as a result of Howell and Anadarko’s drilling and production activities in areas within and near the boundaries of the EBSR. As of December 31, 2007, Williston Basin estimated that between 9.5 and 10 Bcf of storage gas had been diverted from the EBSR as a result of Howell and Anadarko’s drilling and production.

Williston Basin filed suit in Montana Federal District Court in January 2006, seeking to recover unspecified damages from Howell and Anadarko, and to enjoin Howell and Anadarko’s present and future production from specified wells in and near the EBSR. The Montana Federal District Court entered an Order in July 2006, dismissing the case for lack of subject matter jurisdiction. Williston Basin filed a Notice of Appeal to the Ninth Circuit in July 2006. The parties have briefed the issues. Oral argument was held on February 5, 2008.

In related litigation, Howell filed suit in Wyoming State District Court against Williston Basin in February 2006 asserting that it is entitled to produce any gas that might escape from the EBSR. In August 2006, Williston Basin moved for a preliminary injunction to halt Howell and Anadarko’s production in and near the EBSR. A district court-appointed special master conducted a hearing on the motion in December 2006, and recommended denial of the motion on February 15, 2007. The Wyoming State District Court adopted the special master’s report on July 25, 2007, and denied Williston Basin’s motion for a preliminary injunction. On June 25, 2007, the Wyoming State District Court filed a motion with the Wyoming Supreme Court requesting it to answer questions of law concerning the production of Williston Basin’s storage gas by Howell and Anadarko. On July 10, 2007, the Wyoming Supreme Court issued an Order declining to answer those questions. The Wyoming State District Court has set the case for trial beginning September 29, 2008. On December 12, 2007, motions were argued to the special master concerning the application of certain legal principles to the production of Williston Basin’s storage gas by Howell and Anadarko. The parties await a decision.

As noted above, Williston Basin estimates that as of December 31, 2007, Howell and Anadarko had diverted between 9.5 and 10 Bcf from the EBSR. Williston Basin believes Howell and Anadarko continue to divert gas from the EBSR and Williston Basin continues to monitor and analyze the situation. At trial, Williston Basin will seek recovery based on the amount of gas that has been and continues to be diverted as well as on the amount of gas that must be recovered as a result of the equalization of the pressures of various interconnected geological formations.

In expert reports filed with the Wyoming State District Court in January 2008, Williston Basin's experts are of the opinion that all of the gas produced by Howell and Anadarko is Williston Basin's gas and will have to be replaced. Williston Basin's experts estimate that the replacement cost of the gas produced by Howell and Anadarko through October 2007 is approximately $106 million if injection is completed by the end of the 2010 injection season. Williston Basin's experts also estimate that Williston Basin will expend $8.7 million to mitigate the damages that Williston Basin suffered during the period of Howell and Anadarko's production if the replacement gas is injected by the end of the 2010 injection season. Williston Basin believes that its experts' opinions are based on sound law, economics, reservoir engineering, geology and geochemistry. The expert reports filed by Howell and Anadarko claim that storage gas owned by Williston Basin has migrated outside the EBSR into areas in which Howell and Anadarko have oil and gas rights. They theorize that Williston Basin is accountable to Howell and Anadarko for the migration of such gas. Although Howell and Anadarko have not specified the amount of damages they seek to recover, Williston Basin believes Howell and Anadarko's proposed methodology for valuing their alleged injury, if any, is flawed, inconsistent and lacking in factual and legal support. Williston Basin continues to evaluate the Howell and Anadarko reports. The parties have until May 14, 2008, to file rebuttal reports with the Wyoming State District Court.

Williston Basin intends to vigorously defend its rights and interests in these proceedings, to assess further avenues for recovery through the regulatory process at the FERC, and to pursue the recovery of any and all economic losses it may have suffered. Williston Basin cannot predict the ultimate outcome of these proceedings.

In light of the actions of Howell and Anadarko, Williston Basin installed temporary compression at the site in 2006 in order to maintain deliverability into the transmission system. Williston Basin has leased working gas for the 2007 - 2008 heating season to supplement its cushion gas. While installation of the additional compression has provided temporary relief and the addition of leased working gas is expected to provide additional temporary relief, Williston Basin believes that the adverse physical and operational effects occasioned by the continued loss of storage gas, if left unchecked, could threaten the operation and viability of the EBSR, impair Williston Basin's ability to comply with the EBSR certificated operating requirements mandated by the FERC and adversely affect Williston Basin's ability to meet its contractual storage and transportation service commitments to customers.

The Company also is involved in other legal actions in the ordinary course of its business. Although the outcomes of any such legal actions cannot be predicted, management believes that the outcomes with respect to these other legal proceedings will not have a material adverse effect upon the Company's financial position or results of operations.

Environmental matters

Portland Harbor Site In December 2000, MBI was named by the EPA as a Potentially Responsible Party in connection with the cleanup of a riverbed site adjacent to a commercial property site, acquired by MBI in 1999. The riverbed site is part of the Portland, Oregon, Harbor Superfund Site. Sixty-eight other parties were also named in this administrative action. The EPA wants responsible parties to share in the cleanup of sediment contamination in the Willamette River. To date, costs of the overall remedial investigation of the harbor site for both the EPA and the Oregon DEQ are being recorded, and initially paid, through an administrative consent order by the LWG, a group of 10 entities, which does not include MBI or Georgia-Pacific West, Inc., the seller of the commercial property to MBI. Although the LWG originally estimated the overall remedial investigation and feasibility study would cost approximately $10 million, it is now anticipated, on the basis of costs incurred to date and delays attributable to an additional round of sampling and potential further investigative work, that such cost could increase to a total in excess of $60 million. It is not possible to estimate the cost of a corrective action plan until the remedial investigation and feasibility study has been completed, the EPA has decided on a strategy and a record of decision has been published. While the remedial investigation and feasibility study for the harbor site has commenced, it is expected to take several more years to complete. The development of a proposed plan and record of decision on the harbor site is not anticipated to occur until 2010, after which a cleanup plan will be undertaken. MBI also received notice in January 2008 that the Portland Harbor Natural Resource Trustee Council intends to perform an injury assessment to natural resources resulting from the release of hazardous substances at the Harbor Superfund Site. The Trustee Council indicates the injury determination is appropriate to facilitate early settlement of damages and restoration for natural resource injuries.

Based upon a review of the Portland Harbor sediment contamination evaluation by the Oregon DEQ and other information available, MBI does not believe it is a Responsible Party. In addition, MBI has notified Georgia-Pacific West, Inc., that it intends to seek indemnity for any and all liabilities incurred in relation to the above matters, pursuant to the terms of their sale agreement. MBI has entered into an agreement tolling the statute of limitation in connection with the LWG's potential claim for contribution to the costs of the remedial investigation and feasibility study.

The Company believes it is not probable that it will incur any material environmental remediation costs or damages in relation to the above referenced administrative action.

Manufactured Gas Plant Sites There are two claims against Cascade for cleanup of environmental contamination at manufactured gas plant sites operated by Cascade's predecessors.

The first claim is for soil and groundwater contamination at a site in Oregon and was received in 1995. There are potentially responsible parties in addition to Cascade that are potentially liable for cleanup of the contamination. Some of these other parties have shared in the investigation costs. It is expected that these and other potentially responsible parties will share in the cleanup costs. Several alternatives for cleanup have been identified, with preliminary cost estimates ranging from approximately $500,000 to $11.0 million. It is not known at this time what share of the cleanup costs will actually be borne by Cascade. In November 2007, the Oregon Department of Environmental Quality provided notice that additional ecological risk assessment of the site was necessary. Completion of the assessment is anticipated by the end of 2008.

The second claim is for contamination at a site in Washington and was received in 1997. Although a preliminary investigation has concluded the site is contaminated, it appears that other property owners may have contributed to the contamination. There is currently not enough information available to estimate the potential liability associated with this claim and no formal investigation plan has been communicated to Cascade.

The Company believes that both these claims are covered by insurance. To the extent not covered by insurance, Cascade will seek recovery of contamination remediation costs through its rates.

Operating leases
The Company leases certain equipment, facilities and land under operating lease agreements. The amounts of annual minimum lease payments due under these leases as of December 31, 2007, were $20.3 million in 2008, $16.0 million in 2009, $13.7 million in 2010, $10.3 million in 2011, $8.4 million in 2012 and $48.8 million thereafter. Rent expense was $35.6 million, $23.1 million and $33.3 million for the years ended December 31, 2007, 2006 and 2005, respectively.

Purchase commitments
The Company has entered into various commitments, largely natural gas and coal supply, purchased power, natural gas transportation and construction materials supply contracts. These commitments range from one to 53 years. The commitments under these contracts as of December 31, 2007, were $479.2 million in 2008, $340.0 million in 2009, $233.4 million in 2010, $163.7 million in 2011, $105.6 million in 2012 and $323.1 million thereafter. Amounts purchased under various commitments for the years ended December 31, 2007, 2006 and 2005, were approximately $857.0 million (including the acquisition of Cascade as discussed in Note 2), $265.8 million and $318.1 million, respectively. These commitments are not reflected in the Company's consolidated financial statements.

Guarantees

In connection with the sale of MPX in June 2005 to Petrobras, an indirect wholly owned subsidiary of the Company has agreed to indemnify Petrobras for 49 percent of any losses which Petrobras may incur from certain contingent liabilities specified in the purchase agreement. Centennial has agreed to unconditionally guarantee payment of the indemnity obligations to Petrobras for periods ranging up to five and a half years from the date of sale. The guarantee was required by Petrobras as a condition to closing the sale of MPX.

Centennial continues to guarantee CEM's obligations under a construction contract for a 550-MW combined-cycle electric generating facility near Hobbs, New Mexico. As described in Note 3, Centennial Resources sold CEM in July 2007 to Bicent Power LLC, which has provided a $10 million bank letter of credit to Centennial in support of that guarantee obligation. The guarantee, which has no fixed maximum, expires when CEM has completed its obligations under the construction contract. Construction is expected to be completed in 2008, and the warranty period associated with this project will expire one year after the date of substantial completion of the construction.

In addition, WBI Holdings has guaranteed certain of Fidelity's natural gas and oil price swap and collar agreement obligations. There is no fixed maximum amount guaranteed in relation to the natural gas and oil price swap and collar agreements, as the amount of the obligation is dependent upon natural gas and oil commodity prices. The amount of hedging activity entered into by the subsidiary is limited by corporate policy. The guarantees of the natural gas and oil price swap and collar agreements at December 31, 2007, expire in 2008; however, Fidelity continues to enter into additional hedging activities and, as a result, WBI Holdings from time to time may issue additional guarantees on these hedging obligations. The amount outstanding by Fidelity was $1.4 million and was reflected on the Consolidated Balance Sheet at December 31, 2007. In the event Fidelity defaults under its obligations, WBI Holdings would be required to make payments under its guarantees.

Certain subsidiaries of the Company have outstanding guarantees to third parties that guarantee the performance of other subsidiaries of the Company. These guarantees are related to construction contracts, natural gas transportation and sales agreements, gathering contracts, a conditional purchase agreement and certain other guarantees. At December 31, 2007, the fixed maximum amounts guaranteed under these agreements aggregated $472.9 million. The amounts of scheduled expiration of the maximum amounts guaranteed under these agreements aggregate $86.3 million in 2008; $355.8 million in 2009; $400,000 in 2010; $23.0 million in 2011; $1.2 million in 2012; $1.2 million in 2017; $1.0 million which is subject to expiration 30 days after the receipt of written notice; and $4.0 million, which has no scheduled maturity date. The amount outstanding by subsidiaries of the Company under the above guarantees was $1.9 million and was reflected on the Consolidated Balance Sheet at December 31, 2007. In the event of default under these guarantee obligations, the subsidiary issuing the guarantee for that particular obligation would be required to make payments under its guarantee.

Certain subsidiaries have outstanding letters of credit to third parties related to insurance policies, natural gas transportation agreements and other agreements that guarantee the performance of other subsidiaries of the Company. At December 31, 2007, the fixed maximum amounts guaranteed under these letters of credit, which expire in 2008, aggregated $58.4 million. There were no amounts outstanding under the above letters of credit at December 31, 2007.

Fidelity and WBI Holdings have outstanding guarantees to Williston Basin. These guarantees are related to natural gas transportation and storage agreements that guarantee the performance of Prairielands. At December 31, 2007, the fixed maximum amounts guaranteed under these agreements aggregated $22.9 million. Scheduled expiration of the maximum amounts guaranteed under these agreements aggregate $2.9 million in 2008 and $20.0 million in 2009. In the event of Prairielands' default in its payment obligations, the subsidiary issuing the guarantee for that particular obligation would be required to make payments under its guarantee. The amount outstanding by Prairielands under the above guarantees was $1.9 million, which was not reflected on the Consolidated Balance Sheet at December 31, 2007, because these intercompany transactions are eliminated in consolidation.

In addition, Centennial and Knife River have issued guarantees to third parties related to the Company's routine purchase of maintenance items, materials and lease obligations for which no fixed maximum amounts have been specified. These guarantees have no scheduled maturity date. In the event a subsidiary of the Company defaults under its obligation in relation to the purchase of certain maintenance items or lease obligations, Centennial or Knife River would be required to make payments under these guarantees. Any amounts outstanding by subsidiaries of the Company for these maintenance items and materials were reflected on the Consolidated Balance Sheet at December 31, 2007.

In the normal course of business, Centennial has purchased surety bonds related to construction contracts and reclamation obligations of its subsidiaries. In the event a subsidiary of Centennial does not fulfill a bonded obligation, Centennial would be responsible to the surety bond company for completion of the bonded contract or obligation. A large portion of the surety bonds is expected to expire within the next 12 months; however, Centennial will likely continue to enter into surety bonds for its subsidiaries in the future. As of December 31, 2007, approximately $455 million of surety bonds were outstanding, which were not reflected on the Consolidated Balance Sheet.

NOTE 21 - SUBSEQUENT EVENT

On January 31, 2008, Fidelity completed the acquisition of natural gas properties located in Rusk County in eastern Texas, with a January 1, 2008, effective date. The acquisition includes the purchase of 97 Bcfe of proven reserves. The purchase price for these properties was approximately $235 million, subject to accounting and purchase price adjustments customary with acquisitions of this type.

SUPPLEMENTARY FINANCIAL INFORMATION

Quarterly Data (Unaudited)

The following unaudited information shows selected items by quarter for the years 2007 and 2006:

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
	(In thousands, except per share amounts)			
2007				
Operating revenues	$ 787,491	$ 982,365	$ 1,245,310	$ 1,232,730
Operating expenses	708,522	839,580	1,066,154	1,076,520
Operating income	78,969	142,785	179,156	156,210
Income from continuing operations	41,407	82,036	104,497	94,846
Income (loss) from discontinued operations, net of tax	5,255	7,439	96,765	(125)
Net income	46,662	89,475	201,262	94,721
Earnings per common share – basic:				
Earnings before discontinued operations	.23	.45	.57	.52
Discontinued operations, net of tax	.03	.04	.53	---
Earnings per common share – basic	.26	.49	1.10	.52
Earnings per common share – diluted:				
Earnings before discontinued operations	.23	.45	.57	.52
Discontinued operations, net of tax	.02	.04	.53	---
Earnings per common share – diluted	.25	.49	1.10	.52
Weighted average common shares outstanding:				
Basic	181,341	181,847	182,192	182,391
Diluted	182,337	182,746	183,171	183,342

2006

Operating revenues	$ 803,519	$ 961,435	$ 1,173,678	$ 1,065,907
Operating expenses	712,451	839,205	992,249	937,559
Operating income	91,068	122,230	181,429	128,348
Income from continuing operations	52,445	68,451	107,110	79,772
Income from discontinued operations, net of tax	801	2,991	1,377	2,810
Net income	53,246	71,442	108,487	82,582
Earnings per common share – basic:				
Earnings before discontinued operations	.29	.38	.59	.44
Discontinued operations, net of tax	.01	.02	.01	.02
Earnings per common share – basic	.30	.40	.60	.46
Earnings per common share – diluted:				
Earnings before discontinued operations	.29	.38	.59	.44
Discontinued operations, net of tax	---	.01	.01	.01
Earnings per common share – diluted	.29	.39	.60	.45
Weighted average common shares outstanding:				
Basic	179,823	179,911	180,291	180,900
Diluted	180,915	181,107	181,307	182,094

Certain Company operations are highly seasonal and revenues from and certain expenses for such operations may fluctuate significantly among quarterly periods. Accordingly, quarterly financial information may not be indicative of results for a full year.

Natural Gas and Oil Activities (Unaudited)

Fidelity is involved in the acquisition, exploration, development and production of natural gas and oil resources. Fidelity's activities include the acquisition of producing properties with potential development opportunities, exploratory drilling and the operation and development of production properties. Fidelity shares revenues and expenses from the development of specified properties located in the Rocky Mountain and Mid-Continent regions of the United States and in and around the Gulf of Mexico in proportion to its ownership interests.

Fidelity owns in fee or holds natural gas leases for the properties it operates in Colorado, Montana, North Dakota, Texas, Utah and Wyoming. These rights are in the Bonny Field located in eastern Colorado, the Baker Field in southeastern Montana and southwestern North Dakota, the Bowdoin area located in north-central Montana, the Powder River Basin of Montana and Wyoming, the Bakken formation in North Dakota, the Paradox Basin of Utah, the Tabasco and Texan Gardens fields in Texas, and the Big Horn Basin in Wyoming.

The information that follows includes Fidelity's proportionate share of all its natural gas and oil interests.

The following table sets forth capitalized costs and accumulated depreciation, depletion and amortization related to natural gas and oil producing activities at December 31:

	2007	2006	2005
		(In thousands)	
Subject to amortization	$ 1,750,233	$ 1,442,533	$ 1,198,669
Not subject to amortization	142,524	163,975	82,291
Total capitalized costs	1,892,757	1,606,508	1,280,960
Less accumulated depreciation, depletion and amortization	681,101	558,980	456,554

Net capitalized costs	$ 1,211,656	$ 1,047,528	$ 824,406

Capital expenditures, including those not subject to amortization, related to natural gas and oil producing activities were as follows:

Years ended December 31,	2007*	2006*	2005*
		(In thousands)	
Acquisitions:			
Proved properties	$ 426	$ 75,520	$ 149,253
Unproved properties	17,731	27,383	16,920
Exploration	48,744	24,970	24,385
Development**	214,433	196,423	125,633
Total capital expenditures	$ 281,334	$ 324,296	$ 316,191

* Excludes net additions to property, plant and equipment related to the recognition of future liabilities associated with the plugging and abandonment of natural gas and oil wells in accordance with SFAS No. 143, as discussed in Note 11, of $5.4 million, $8.7 million and $2.5 million for the years ended December 31, 2007, 2006 and 2005, respectively.

** Includes expenditures for proved undeveloped reserves of $74.6 million, $44.7 million and $37.0 million for the years ended December 31, 2007, 2006 and 2005, respectively.

The following summary reflects income resulting from the Company's operations of natural gas and oil producing activities, excluding corporate overhead and financing costs:

Years ended December 31,	2007	2006	2005
		(In thousands)	
Revenues:			
Sales to affiliates	$ 226,706	$ 232,799	$ 275,828
Sales to external customers	287,557	244,499	159,390
Production costs	123,924	106,387	88,068
Depreciation, depletion and amortization*	124,599	104,741	84,099
Pretax income	265,740	266,170	263,051
Income tax expense	98,729	100,584	99,071
Results of operations for producing activities	$ 167,011	$ 165,586	$ 163,980

* Includes accretion of discount for asset retirement obligations of $2.5 million, $2.3 million and $1.5 million for the years ended December 31, 2007, 2006 and 2005, respectively, in accordance with SFAS No. 143, as discussed in Note 11.

The following table summarizes the Company's estimated quantities of proved natural gas and oil reserves at December 31, 2007, 2006 and 2005, and reconciles the changes between these dates. Estimates of economically recoverable natural gas and oil reserves and future net revenues therefrom are based upon a number of variable factors and assumptions. For these reasons, estimates of economically recoverable reserves and future net revenues may vary from actual results.

	2007		2006		2005	
	Natural Gas	Oil	Natural Gas	Oil	Natural Gas	Oil
			(MMcf/MBbls)			
Proved developed and undeveloped reserves:						

Balance at beginning of year	538,100	27,100	489,100	21,200	453,200	17,100
Production	(62,798)	(2,365)	(62,100)	(2,100)	(59,400)	(1,700)
Extensions and discoveries	77,701	3,772	123,600	2,800	74,400	500
Improved recovery	444	1,614	---	---	---	2,600
Purchases of proved reserves	2	6	21,700	4,800	57,400	3,700
Sales of reserves in place	(6)	(42)	---	---	(1,300)	(100)
Revisions of previous estimates	(29,706)	527	(34,200)	400	(35,200)	(900)
Balance at end of year	523,737	30,612	538,100	27,100	489,100	21,200
Proved developed reserves:						
January 1, 2005					376,400	16,400
December 31, 2005					416,700	20,400
December 31, 2006					412,900	22,400
December 31, 2007					420,137	25,658

The Company's interests in natural gas and oil reserves are located in the United States and in and around the Gulf of Mexico.

The standardized measure of the Company's estimated discounted future net cash flows of total proved reserves associated with its various natural gas and oil interests at December 31 was as follows:

	2007	2006	2005
		(In thousands)	
Future cash inflows	$ 5,302,300	$ 3,831,000	$ 4,778,700
Future production costs	1,415,700	1,084,000	1,095,400
Future development costs	237,600	240,600	106,400
Future net cash flows before income taxes	3,649,000	2,506,400	3,576,900
Future income tax expense	1,179,900	759,300	1,205,700
Future net cash flows	2,469,100	1,747,100	2,371,200
10% annual discount for estimated timing of cash flows	1,107,200	743,600	950,400
Discounted future net cash flows relating to proved natural gas and oil reserves	$ 1,361,900	$ 1,003,500	$ 1,420,800

The following are the sources of change in the standardized measure of discounted future net cash flows by year:

	2007	2006	2005
		(In thousands)	
Beginning of year	$ 1,003,500	$ 1,420,800	$ 821,500
Net revenues from production	(354,100)	(348,400)	(402,900)
Change in net realization	527,900	(860,700)	777,700
Extensions and discoveries, net of future production-related costs	310,300	293,300	294,800
Improved recovery, net of future production-related costs	38,100	---	91,600
Purchases of proved reserves, net of future production-related costs	200	99,800	258,300
Sales of reserves in place	(1,300)	---	(12,500)
Changes in estimated future development costs	(22,600)	(25,600)	(13,400)
Development costs incurred during the current year	103,000	60,900	40,900
Accretion of discount	133,700	193,800	106,900
Net change in income taxes	(212,500)	295,700	(339,700)

Revisions of previous estimates	(163,700)	(123,200)	(200,500)
Other	(600)	(2,900)	(1,900)
Net change	358,400	(417,300)	599,300
End of year	$ 1,361,900	$ 1,003,500	$ 1,420,800

The estimated discounted future cash inflows from estimated future production of proved reserves were computed using year-end natural gas and oil prices. Future development and production costs attributable to proved reserves were computed by applying year-end costs to be incurred in producing and further developing the proved reserves. Future development costs estimated to be spent in each of the next three years to develop proved undeveloped reserves as of December 31, 2007, are $94.5 million in 2008, $48.0 million in 2009 and $19.2 million in 2010. Future income tax expenses were computed by applying statutory tax rates, adjusted for permanent differences and tax credits, to estimated net future pretax cash flows.

The standardized measure of discounted future net cash flows does not purport to represent the fair market value of natural gas and oil properties. There are significant uncertainties inherent in estimating quantities of proved reserves and in projecting rates of production and the timing and amount of future costs. In addition, future realization of natural gas and oil prices over the remaining reserve lives may vary significantly from current prices.

ITEM 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

None.

ITEM 9A. CONTROLS AND PROCEDURES

The following information includes the evaluation of disclosure controls and procedures by the Company's chief executive officer and the chief financial officer, along with any significant changes in internal controls of the Company.

EVALUATION OF DISCLOSURE CONTROLS AND PROCEDURES

The term "disclosure controls and procedures" is defined in Rules 13a-15(e) and 15d-15(e) of the Exchange Act. These rules refer to the controls and other procedures of a company that are designed to ensure that information required to be disclosed by a company in the reports that it files under the Exchange Act is recorded, processed, summarized and reported within required time periods. The Company's chief executive officer and chief financial officer have evaluated the effectiveness of the Company's disclosure controls and procedures and they have concluded that, as of the end of the period covered by this report, such controls and procedures were effective.

CHANGES IN INTERNAL CONTROLS

The Company maintains a system of internal accounting controls that is designed to provide reasonable assurance that the Company's transactions are properly authorized, the Company's assets are safeguarded against unauthorized or improper use, and the Company's transactions are properly recorded and reported to permit preparation of the Company's financial statements in conformity with generally accepted accounting principles in the United States of America. There were no changes in the Company's internal control over financial reporting that occurred during the quarter ended December 31, 2007, that have materially affected, or are reasonably likely to materially affect, the Company's internal control over financial reporting.

MANAGEMENT'S ANNUAL REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

The information required by this item is included in this Form 10-K at Item 8 – Management's Report on Internal Control Over Financial Reporting.

ATTESTATION REPORT OF THE REGISTERED PUBLIC ACCOUNTING FIRM

The information required by this item is included in this Form 10-K at Item 8 – Report of Independent Registered Public Accounting Firm.

ITEM 9B. OTHER INFORMATION

None.

PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

The information required by this item is included under the captions "Item 1. Election of Directors – Director Nominees for One Year Term," "Continuing Incumbent Directors," "Information Concerning Executive Officers," the first paragraph, the second sentence of the second paragraph and third paragraph under "Corporate Governance – Audit Committee," "Corporate Governance – Code of Conduct," the last paragraph under "Corporate Governance – Board Meetings and Committees" and "Section 16(a) Beneficial Ownership Reporting Compliance" in the Proxy Statement, which information is incorporated herein by reference.

ITEM 11. EXECUTIVE COMPENSATION

The information required by this item is included under the caption "Executive Compensation" in the Proxy Statement, which information is incorporated herein by reference.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS

EQUITY COMPENSATION PLAN INFORMATION

The following table includes information as of December 31, 2007, with respect to the Company's equity compensation plans:

Plan Category	(a) Number of securities to be issued upon exercise of outstanding options, warrants and rights	(b) Weighted average exercise price of outstanding options, warrants and rights	(c) Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in column (a))
Equity compensation plans approved by stockholders (1)	1,568,549 (2)	$16.88	7,816,197 (3)(4)
Equity compensation plans not approved by stockholders (5)	613,319	12.90	2,323,915 (6)
Total	2,181,868	$15.76	10,140,112

(1) Consists of the 1992 Key Employee Stock Option Plan, the 1997 Non-Employee Director Long-Term Incentive Plan, the Long-Term Performance-Based Incentive Plan (formerly known as the 1997 Executive Long-Term Incentive Plan) and the Non-Employee Director Stock Compensation Plan.

(2) Includes 685,960 performance shares.

(3) In addition to being available for future issuance upon exercise of options, 357,757 shares under the 1997 Non-Employee Director Long-Term Incentive Plan may instead be issued in connection with stock appreciation rights, restricted stock, performance units, performance shares or other equity-based awards, and 6,320,232 shares under the Long-Term Performance-Based Incentive Plan may instead be issued in connection with stock appreciation rights, restricted stock, performance units, performance shares or other equity-based awards.

(4) This amount also includes 459,952 shares available for issuance under the Non-Employee Director Stock Compensation Plan. Under this plan, in addition to a cash retainer, nonemployee Directors are awarded 4,050

(adjusted for the three-for-two stock split in July 2006) shares following the Company's annual meeting of stockholders. Additionally, a nonemployee Director may acquire additional shares under the plan in lieu of receiving the cash portion of the Director's retainer or fees.

(5) Consists of the 1998 Option Award Program and the Group Genius Innovation Plan.

(6) In addition to being available for future issuance upon exercise of options, 220,050 shares under the Group Genius Innovation Plan may instead be issued in connection with stock appreciation rights, restricted stock, restricted stock units, performance units, performance stock or other equity-based awards.

The following equity compensation plans have not been approved by the Company's stockholders.

The 1998 Option Award Program

The 1998 Option Award Program is a broad-based plan adopted by the Board of Directors, effective February 12, 1998. The plan permits the grant of nonqualified stock options to employees of the Company and its subsidiaries. The maximum number of shares that may be issued under the plan is 3,795,330. Shares granted may be authorized but unissued shares, treasury shares, or shares purchased on the open market. Option exercise prices are equal to the market value of the Company's shares on the date of the option grant. Optionees receive dividend equivalents on their options, with any credited dividends paid in cash to the optionee if the option vests, or forfeited if the option is forfeited. Vested options remain exercisable for one year following termination of employment due to death or disability and for three months following termination of employment for any other reason.

Unvested options are forfeited upon termination of employment. Subject to the terms and conditions of the plan, the plan's administrative committee determines the number of shares subject to options granted to each participant and the other terms and conditions pertaining to such options, including vesting provisions. All options become immediately exercisable in the event of a change in control of the Company.

In 1998, 337 options (adjusted for the three-for-two stock splits in July 1998, October 2003 and July 2006) were granted to each of approximately 2,200 employees. No officers received grants. These options vested on March 2, 2001. In 2001, 450 options (adjusted for the three-for-two stock splits in October 2003 and July 2006) were granted to each of approximately 5,900 employees. No officers received grants. These options vested on February 13, 2004. As of December 31, 2007, options covering 613,319 shares of common stock were outstanding under the plan and 2,103,865 shares remained available for future grant. Options covering 1,078,146 shares had been exercised.

The Group Genius Innovation Plan

The Group Genius Innovation Plan was adopted by the Board of Directors, effective May 17, 2001, to encourage employees to share ideas for new business directions for the Company and to reward them when the idea becomes profitable. Employees of the Company and its subsidiaries who are selected by the plan's administrative committee are eligible to participate in the plan. Officers and Directors are not eligible to participate. The plan permits the granting of nonqualified stock options, stock appreciation rights, restricted stock, restricted stock units, performance units, performance stock and other awards. The maximum number of shares that may be issued under the plan is 223,150. Shares granted under the plan may be authorized but unissued shares, treasury shares or shares purchased on the open market. Restricted stockholders have voting rights and, unless determined otherwise by the plan's administrative committee, receive dividends paid on the restricted stock. Dividend equivalents payable in cash may be granted with respect to options and performance shares. The plan's administrative committee determines the number of shares or units subject to awards, and the other terms and conditions of the awards, including vesting provisions and the effect of employment termination. Upon a change in control of the Company, all options and stock appreciation rights become immediately vested and exercisable, all restricted stock becomes immediately vested, all restricted stock units become immediately vested and are paid out in cash, and target payout opportunities under all performance units, performance stock, and other awards are deemed to be fully earned, with awards denominated in stock paid out in shares and awards denominated in units paid out in cash. As of December 31, 2007, −−−−−3,100 shares of stock had been granted to 56 employees.

The remaining information required by this item is included under the caption "Security Ownership” of the Proxy Statement, which is incorporated herein by reference.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS, AND DIRECTOR INDEPENDENCE

The information required by this item is included under the captions “Related Person Disclosure” and “Corporate Governance – Director Independence” in the Proxy Statement, which information is incorporated herein by reference.

ITEM 14. PRINCIPAL ACCOUNTANT FEES AND SERVICES

The information required by this item is included under the caption "Accounting and Auditing Matters" of the Proxy Statement, which information is incorporated herein by reference.

PART IV

ITEM 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES

(a) FINANCIAL STATEMENTS, FINANCIAL STATEMENT SCHEDULES AND EXHIBITS

Index to Financial Statements and Financial Statement Schedules

1. Financial Statements
The following consolidated financial statements required under this item are included under Item 8 – Financial Statements and Supplementary Data.

Consolidated Statements of Income for each of the three years in the period ended December 31, 2007

Consolidated Balance Sheets at December 31, 2007 and 2006

Consolidated Statements of Common Stockholders' Equity for each of the three years in the period ended December 31, 2007

Consolidated Statements of Cash Flows for each of the three years in the period ended December 31, 2007

Notes to Consolidated Financial Statements

2. Financial Statement Schedules

MDU Resources Group, Inc.
Schedule II - Consolidated Valuation and Qualifying Accounts
Years Ended December 31, 2007, 2006 and 2005

Description	Balance at Beginning of Year	Additions: Charged to Costs and Expenses	Additions: Other*	Deductions**	Balance at End of Year
			(In thousands)		
Allowance for doubtful accounts:					
2007	$7,725	$8,799	$5,533	$7,422	$14,635
2006	8,031	5,470	1,576	7,352	7,725
2005	6,801	4,870	1,675	5,315	8,031

* Allowance for doubtful accounts for companies acquired and recoveries.
** Uncollectible accounts written off.

All other schedules are omitted because of the absence of the conditions under which they are required, or because the information required is included in the Company's Consolidated Financial Statements and Notes thereto.

3. Exhibits

2 Agreement and Plan of Merger by and among MDU Resources Group, Inc., Firemoon Acquisition, Inc. and Cascade Natural Gas Corporation dated as of July 8, 2006, filed by Cascade Natural Gas Corporation as Exhibit 2.1 to Form 8-K dated July 10, 2006, in File No. 1-7196* (1)

3(a) Restated Certificate of Incorporation of the Company, as amended, filed as Exhibit 3.1 to Form 8-A/A, as amended, filed on June 27, 2007, in File No. 1-3480*

3(b) Company Bylaws, as amended, filed as Exhibit 3.1 to Form 8-K dated November 16, 2006, filed on November 22, 2006, in File No. 1-3480*

3(c) Certificate of Designations of Series B Preference Stock of the Company, as amended, filed as Exhibit 3(a) to Form 10-Q for the quarter ended September 30, 2002, filed on November 14, 2002, in File No. 1-3480*

4(a) Indenture of Mortgage, dated as of May 1, 1939, as restated in the Forty-Fifth Supplemental Indenture, dated as of April 21, 1992, and the Forty-Sixth through Forty-Ninth Supplements thereto between the Company and the New York Trust Company (The Bank of New York, successor Corporate Trustee) and A. C. Downing (Douglas J. MacInnes, successor Co-Trustee), filed as Exhibit 4(a) to Form S-3, in Registration No. 33-66682; and Exhibits 4(e), 4(f) and 4(g) to Form S-8, in Registration No. 33-53896; and Exhibit 4(c)(i) to Form S-3, in Registration No. 333-49472*

4(b) Fiftieth Supplemental Indenture, dated as of December 15, 2003, filed as Exhibit 4(e) to Form S-8 on January 21, 2004, in Registration No. 333-112035*

4(c) Rights Agreement, dated as of November 12, 1998, between the Company and Wells Fargo Bank Minnesota, N.A. (formerly known as Norwest Bank Minnesota, N.A.), Rights Agent, filed as Exhibit 4.1 to Form 8-A on November 12, 1998, in File No. 1-3480*

4(d) Indenture, dated as of December 15, 2003, between the Company and The Bank of New York, as trustee, filed as Exhibit 4(f) to Form S-8 on January 21, 2004, in Registration No. 333-112035*

4(e) Certificate of Adjustment to Purchase Price and Redemption Price, as amended and restated, pursuant to the Rights Agreement, dated as of November 12, 1998, filed as Exhibit 4(c) to Form 10-Q for the quarter ended June 30, 2006, filed on August 4, 2006, in File No. 1-3480*

4(f) Centennial Energy Holdings, Inc. Master Shelf Agreement, dated April 29, 2005, among Centennial Energy Holdings, Inc. and the Prudential Insurance Company of America, filed as Exhibit 4(a) to Form 10-Q for the quarter ended June 30, 2005, filed on August 3, 2005, in File No. 1-3480*

4(g) Letter Amendment No. 1 to Amended and Restated Master Shelf Agreement, dated May 17, 2006, among Centennial Energy Holdings, Inc., The Prudential Insurance Company of America, and certain investors described in the Letter Amendment filed as Exhibit 4(a) to Form 10-Q for the quarter ended June 30, 2006, filed on August 4, 2006, in File No. 1-3480*

4(h) MDU Resources Group, Inc. Credit Agreement, dated June 21, 2005, among MDU Resources Group, Inc., Wells Fargo Bank, National Association, as Administrative Agent, and The Other Financial Institutions Party thereto, filed as Exhibit 4(b) to Form 10-Q for the quarter ended June 30, 2005, filed on August 3, 2005, in File No. 1-3480*

4(i) First Amendment, dated June 30, 2006, to Credit Agreement, dated June 21, 2005, among MDU Resources Group, Inc., Wells Fargo Bank, National Association, as administrative agent, and certain lenders described in the credit agreement, filed as Exhibit 4(b) to Form 10-Q for the quarter ended June 30, 2006, filed on August 4, 2006, in File No. 1-3480*

4(j) Centennial Energy Holdings, Inc. Credit Agreement, dated December 13, 2007, among Centennial Energy Holdings, Inc., U.S. Bank National Association, as Administrative Agent, and The Other Financial Institutions party thereto**

4(k) MDU Resources Group, Inc. Term Loan Agreement, dated June 29, 2007, among MDU Resources Group, Inc., Wells Fargo Bank, National Association, as Administrative Agent, and The Other Financial Institutions party thereto, filed as Exhibit 4 to Form 10-Q for the quarter ended June 30, 2007, filed on August 8, 2007, in File No. 1-3480*

4(l) MDU Energy Capital, LLC Master Shelf Agreement, dated as of August 9, 2007, among MDU Energy Capital, LLC and the Prudential Insurance Company of America, filed as Exhibit 4 to Form 8-K dated August 16, 2007, filed on August 16, 2007, in File No. 1-3480*

4(m) Indenture dated as of August 1, 1992, between Cascade Natural Gas Corporation and The Bank of New York relating to Medium-Term Notes, filed by Cascade Natural Gas Corporation as Exhibit 4 to Form 8-K dated August 12, 1992, in File No. 1-7196*

4(n) First Supplemental Indenture dated as of October 25, 1993, between Cascade Natural Gas Corporation and The Bank of New York relating to Medium-Term Notes and the 7.5% Notes due November 15, 2031, filed by Cascade Natural Gas Corporation as Exhibit 4 to Form 10-Q for the quarter ended June 30, 1993, in File No. 1-7196*

4(o) Second Supplemental Indenture, dated January 25, 2005, between Cascade Natural Gas Corporation and The Bank of New York, as trustee, filed by Cascade Natural Gas Corporation as Exhibit 4.1 to Form 8-K dated January 25, 2005, filed on January 26, 2005, in File No. 1-7196*

4(p) Third Supplemental Indenture dated as of March 8, 2007, between Cascade Natural Gas Corporation and The Bank of New York Trust Company, N.A., as Successor Trustee, filed by Cascade Natural Gas Corporation as Exhibit 4.1 to Form 8-K dated March 8, 2007, filed on March 8, 2007, in File No. 1-7196*

+10(a) 1992 Key Employee Stock Option Plan, as revised, filed as Exhibit 10(a) to Form 10-K for the year ended December 31, 2006, filed on February 21, 2007, in File No. 1-3480*

+10(b) Supplemental Income Security Plan, as amended and restated, effective November 16, 2006, filed as Exhibit 10(b) to Form 10-K for the year ended December 31, 2006, filed on February 21, 2007, in File No. 1-3480*

+10(c) Directors' Compensation Policy, as amended February 15, 2007, filed as Exhibit 10(c) to Form 10-K for the year ended December 31, 2006, filed on February 21, 2007, in File No. 1-3480*

+10(d) Deferred Compensation Plan for Directors, as amended, filed as Exhibit 10(e) to Form 10-K for the year ended December 31, 2002, filed on February 28, 2003, in File No. 1-3480*

+10(e) Non-Employee Director Stock Compensation Plan, as revised, filed as Exhibit 10(e) to Form 10-K for the year ended December 31, 2006, filed on February 21, 2007, in File No. 1-3480*

+10(f) 1997 Non-Employee Director Long-Term Incentive Plan, as revised, filed as Exhibit 10(f) to Form 10-K for the year ended December 31, 2006, filed on February 21, 2007, in File No. 1-3480*

+10(g) Change of Control Employment Agreement between the Company and Terry D. Hildestad, filed as Exhibit 10(d) to Form 10-Q for the quarter ended September 30, 2002, filed on November 14, 2002, in File No. 1-3480*

+10(h) Change of Control Employment Agreement between the Company and Bruce T. Imsdahl, filed as Exhibit 10(c) to Form 10-Q for the quarter ended June 30, 2004, filed on August 6, 2004, in File No. 1-3480*

+10(i) Change of Control Employment Agreement between the Company and Vernon A. Raile, filed as Exhibit 10(f) to Form 10-Q for the quarter ended September 30, 2002, filed on November 14, 2002, in File No. 1-3480*

+10(j) Change of Control Employment Agreement between the Company and Paul K. Sandness, filed as Exhibit 10(e) to Form 10-Q for the quarter ended June 30, 2004, filed on August 6, 2004, in File No. 1-3480*

+10(k) Change of Control Employment Agreement between the Company and William E. Schneider, filed as Exhibit 10(h) to Form 10-Q for the quarter ended September 30, 2002, filed on November 14, 2002, in File No. 1-3480*

+10(l) Change of Control Employment Agreement between the Company and John G. Harp, filed as Exhibit 10(p) to Form 10-K for the year ended December 31, 2006, filed on February 21, 2007, in File No. 1-3480*

+10(m) 1998 Option Award Program, as revised, filed as Exhibit 10(q) to Form 10-K for the year ended December 31, 2006, filed on February 21, 2007, in File No. 1-3480*

+10(n) Group Genius Innovation Plan, as revised, filed as Exhibit 10(r) to Form 10-K for the year ended December 31, 2006, filed on February 21, 2007, in File No. 1-3480*

10(o) Purchase and Sale Agreement, dated January 4, 2008, between Fidelity and EnerVest Energy Institutional Fund IX, L.P., EnerVest Energy Institutional Fund IX-WI, L.P., and Everstar Energy, LLC**

+10(p) WBI Holdings, Inc. Executive Incentive Compensation Plan and Rules and Regulations, as amended February 26, 2007, filed as Exhibit 10(d) to Form 10-Q for the quarter ended March 31, 2007, filed on May 8, 2007, in File No. 1-3480*

+10(q) Knife River Corporation Executive Incentive Compensation Plan and Rules and Regulations, as amended February 26, 2007, filed as Exhibit 10(e) to Form 10-Q for the quarter ended March 31, 2007, filed on May 8, 2007, in File No. 1-3480*

+10(r) Long-Term Performance-Based Incentive Plan, as revised, filed as Exhibit 10(y) to Form 10-K for the year ended December 31, 2006, filed on February 21, 2007, in File No. 1-3480*

+10(s) MDU Resources Group, Inc. Executive Incentive Compensation Plan and Rules and Regulations, as amended November 15, 2007**

+10(t) Montana-Dakota Utilities Co. Executive Incentive Compensation Plan and Rules and Regulations, as amended November 15, 2007**

+10(u) Change of Control Employment Agreement between the Company and Steven L. Bietz, filed as Exhibit 10(ai) to Form 10-K for the year ended December 31, 2005, filed on February 22, 2006, in File No. 1-3480*

+10(v) Change of Control Employment Agreement between the Company and Nicole A. Kivisto, filed as Exhibit 10(aj) to Form 10-K for the year ended December 31, 2005, filed on February 22, 2006, in File No. 1-3480*

+10(w) Change of Control Employment Agreement between the Company and Doran N. Schwartz, filed as Exhibit 10(ak) to Form 10-K for the year ended December 31, 2005, filed on February 22, 2006, in File No. 1-3480*

+10(x) Supplemental Executive Retirement Plan for John G. Harp, dated December 4, 2006, filed as Exhibit 10(ag) to Form 10-K for the year ended December 31, 2006, filed on February 21, 2007, in File No. 1-3480*

+10(y) Employment Letter for John G. Harp, dated July 20, 2005, filed as Exhibit 10(ah) to Form 10-K for the year ended December 31, 2006, filed on February 21, 2007, in File No. 1-3480*

+10(z) Form of Performance Share Award Agreement under the Long-Term Performance-Based Incentive Plan, as amended November 15, 2007**

10(aa) Centennial Power, Inc. and Colorado Energy Management, LLC Purchase and Sale Agreement by and between Centennial Energy Resources LLC, as Seller, and Montana Acquisition Company LLC, as Buyer, dated April 25, 2007, filed as Exhibit 10(a) to Form 10-Q for the quarter ended March 31, 2007, filed on May 8, 2007, in File No. 1-3480*

+10(ab) MDU Construction Services Group, Inc. Executive Incentive Compensation Plan and Rules and Regulations, as adopted May 2, 2006, filed as Exhibit 10(f) to Form 10-Q for the quarter ended March 31, 2007, filed on May 8, 2007, in File No. 1-3480*

+10(ac) Consulting Agreement, dated July 2, 2007, by and between Williston Basin Interstate Pipeline Company and John K. Castleberry, filed as Exhibit 10 to Form 10-Q for the quarter ended June 30, 2007, filed on August 8, 2007, in File No. 1-3480*

12 Computation of Ratio of Earnings to Fixed Charges and Combined Fixed Charges and Preferred Stock Dividends**

21 Subsidiaries of MDU Resources Group, Inc.**

23 Consent of Independent Registered Public Accounting Firm**

31(a) Certification of Chief Executive Officer filed pursuant to Section 302 of the Sarbanes-Oxley Act of 2002**

31(b) Certification of Chief Financial Officer filed pursuant to Section 302 of the Sarbanes-Oxley Act of 2002**

32 Certification of Chief Executive Officer and Chief Financial Officer furnished pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002**

99(a) Sales Agency Financing Agreement, dated as of July 27, 2006, between the Company and Wells Fargo

Securities, LLC, filed as Exhibit 1 to Form 8-K dated July 27, 2006, filed on July 27, 2006, in File No. 1-3480*

99(b) Amendment to Sales Agency Financing Agreement, dated as of June 25, 2007, between the Company and Wells Fargo Securities, LLC, filed as Exhibit 1 to Form 8-K dated June 25, 2007, filed on June 28, 2007, in File No. 1-3480*

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* Incorporated herein by reference as indicated.
** Filed herewith.
\+ Management contract, compensatory plan or arrangement.

(1) Schedules have been omitted pursuant to Item 601(b)(2) of Regulation S-K. MDU Resources Group, Inc. hereby undertakes to furnish supplementally copies of any of the omitted schedules upon request by the SEC.

MDU Resources Group, Inc. agrees to furnish to the SEC upon request any instrument with respect to long-term debt that MDU Resources Group, Inc. has not filed as an exhibit pursuant to the exemption provided by Item 601(b)(4)(iii)(A) of Regulation S-K.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

MDU RESOURCES GROUP, INC.

Date: February 20, 2008 By: /s/ Terry D. Hildestad
Terry D. Hildestad
(President and Chief Executive Officer)

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant in the capacities and on the date indicated.

Signature	Title	Date
/s/ Terry D. Hildestad Terry D. Hildestad (President and Chief Executive Officer)	Chief Executive Officer and Director	February 20, 2008
/s/ Vernon A. Raile Vernon A. Raile (Executive Vice President, Treasurer and Chief Financial Officer)	Chief Financial Officer	February 20, 2008
/s/ Doran N. Schwartz Doran N. Schwartz (Vice President and Chief Accounting Officer)	Chief Accounting Officer	February 20, 2008
/s/ Harry J. Pearce Harry J. Pearce (Chairman of the Board)	Director	February 20, 2008
/s/ Thomas Everist Thomas Everist	Director	February 20, 2008
/s/ Karen B. Fagg Karen B. Fagg	Director	February 20, 2008
/s/ Dennis W. Johnson Dennis W. Johnson	Director	February 20, 2008
/s/ Richard H. Lewis Richard H. Lewis	Director	February 20, 2008
/s/ Patricia L. Moss	Director	February 20, 2008

Patricia L. Moss		
/s/ John L. Olson John L. Olson	Director	February 20, 2008
/s/ Sister Thomas Welder Sister Thomas Welder	Director	February 20, 2008
/s/ John K. Wilson John K. Wilson	Director	February 20, 2008